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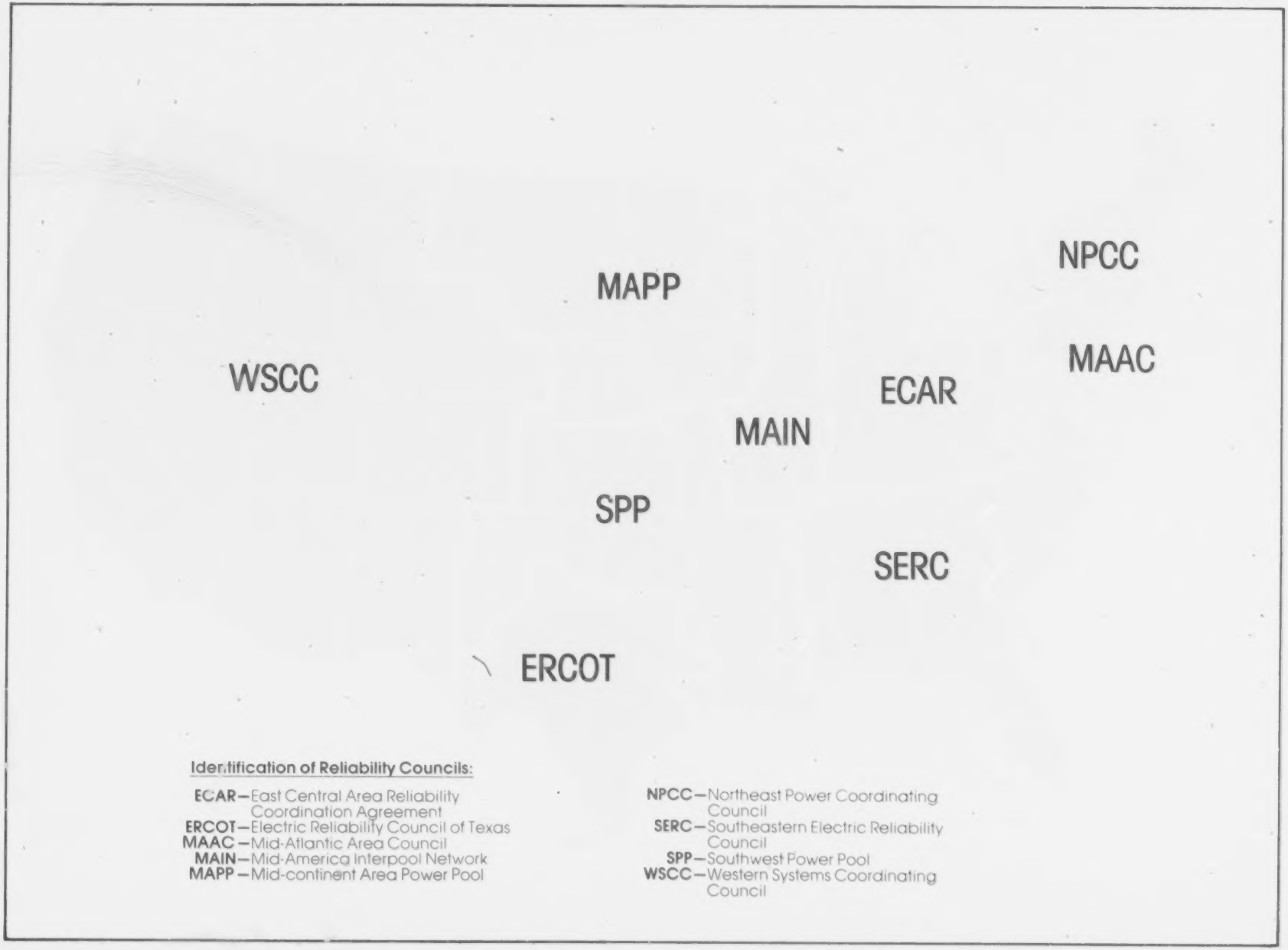
1983 ANNUAL ELECTRIC POWER SURVEY

A Report of the Electric Power Survey Committee of the

EDISON ELECTRIC INSTITUTE The association of electric companies

Fig. 1 U.S. Regions of the North American Electric Reliability Council



A REPORT OF THE ELECTRIC POWER SURVEY COMMITTEE OF THE EDISON ELECTRIC INSTITUTE

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R. V. Knudsen, Midcontinent Area Power Pool
W. A. Lewis, East Central Area Reliability Coordination Agreement
C. L. McNeese, Electric Reliability Council Of Texas
C. V. Walls, Consumers Power Company

MANUFACTURERS' REPRESENTATIVES

Domestic

J. R. Alexander, Westinghouse Electric Corp., Orlando, Florida
R. G. Alsworth, Worthington Div. McGraw-Edison Co., Wellsville, New York
R. G. Carlson, Allis-Chalmers Co., York, Pennsylvania
M. A. Cerce, Elliott Company, Jeannette, Pennsylvania
E. G. Devine, Combustion Engineering, Inc., Windsor, Connecticut
R. G. Donnelly, Transamerica Delaval Inc., Oakland, California
L. A. Ellis, RTE Corp., Waukesha, Wisconsin
J. T. Eunson, Riley Stoker, Worcester, Massachusetts
S. Gammeter, Brown Boveri Turbomachinery, Inc., St. Cloud, Minnesota
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J. R. Groff, The James Leffel & Co., Springfield Ohio
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J. R. Lennartson, Westinghouse Electric Corp., Pittsburgh, Pennsylvania
J. M. Major, General Electric Co., Rome, Georgia
K. McCullough, The Babcock & Wilcox Co., Barberton, Ohio
H. J. Melosh, III, Foster Wheeler Corp., Livingston, New Jersey
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G. E. Pfafflin, Allis-Chalmers Co., York, Pennsylvania
J. G. Popek, Transamerica Delaval, Inc., Trenton, New Jersey
J. J. Reilly, General Electric Co., Lynn, Massachusetts
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W. G. Rogal, Westinghouse Electric Corp., Concordville, Pennsylvania
M. Rolland, Westinghouse Electric Corp., South Boston, Virginia
J. G. Rosenberg, Westinghouse Electric Corp., Pittsburgh, Pennsylvania
J. E. Taucher, Cooper Energy Services, Grove City, Pennsylvania
T. F. Tobin, Riley Stoker Corp., Worcester, Massachusetts
H. B. Williams, General Electric Co., Pittsfield, Massachusetts

Foreign

T. Henry, Canadian General Electric Co., Ltd., Peterborough, Ontario, Canada
R. J. Hoefling, Siemens Corp., Iselin, New Jersey
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T. Shirasawa, Chairman-Japan Electric Power Survey Committee, Tokyo, Japan
Z. Stanley Stys, Brown Boveri Corp., North Brunswick, New Jersey
K. Yamawaki, Japan Electric Power Survey Committee, Tokyo, Japan
Hirokichi Yoshiyama, Hitachi, Ltd., Tokyo, Japan

CONTENTS

Foreword 3

Definitions and Methods of Summarization 4

Part I. Electric Power Supply 5

Peak Capabilities, Peak Loads, and Capability Margins 5
Relationship Between Summer and Winter Peak Loads 12
Kilowatt-Hour Requirements 14
Annual Load Factors 16
Comparison With Previous Fuel Survey 17
Fossil Fuel Requirements for Electric Generation in Physical Units 20
Net Generation by Source, Fuels and Hydro—Millions of Kilowatt-Hours 18
Additions to Electric Generating Capacity 22
Nuclear Electric Power 24

Part II. Manufacture of Heavy Electric Power Equipment in the U.S.A. 26

Manufacture of Electric Generating Equipment, Steam and Hydraulic Units—4,000 Kw and Larger 27
Manufacture of Steam Turbine-Generators—4,000 Kw and Larger 28
Manufacture of Conventional Steam Turbine-Generators—4,000 Kw and Larger 29
Manufacture of Nuclear Steam Turbine-Generators—50,000 Kw and Larger 30
Manufacture of Generators for Hydraulic Turbines—4,000 Kw and Larger 31
Manufacture of Conventional Steam Generators—450-Psi Pressure and Higher 32
Manufacture of Hydraulic Turbines—5,000 Horsepower and Larger 33
Manufacture of Combustion Turbine-Generators—4,000 Kw and Larger 34
Manufacture of Power Transformers—501 Kva and Larger 35
Manufacture of Nuclear Power Reactors—50,000 Kwe and Larger 36

Appendix I

Scheduled Additions to Electric Generating Capacity Based on Scheduled Dates of Commercial Operation as of April 1, 1983, and Including Capacity Placed in Service During the First Three Months of 1983 37

1983 ANNUAL ELECTRIC POWER SURVEY

FOREWORD

The electric power supply data shown in Part I of this report are derived partly from EP-411 reports for the years 1981 and 1982 submitted to the United States Department of Energy, and partly by direct reports to the head office of the North American Electric Reliability Council (NERC) in Princeton, New Jersey, by the regional reliability councils. Forecast values used herein are those compiled and validated by NERC HQ and published in their report, ELECTRIC POWER SUPPLY AND DEMAND 1983–1992. Historical capability values for the 1982/83 winter season are missing from Table 2 on page 8 of this issue. The values could not be calculated because NERC did not ask for actual installed capability for the winter of 1982/83 on its 83-IRS questionnaire.

Until two years ago, Annual Electric Power Survey power supply figures had been obtained by means of questionnaires sent to the regional and subregional utility reporting entities by EEI on behalf of the Electric Power Survey Committee. The historical and forecast power supply data in this report are all from the new data source (NERC) and are internally consistent. For a discussion of the magnitude of the break between the old EEI-collected series and the NERC-collected series now reformatted for publication in these annual surveys, see the FOREWORD in the 1981 Annual Electric Power Survey.

Data in this survey represent the entire electric utility industry of the contiguous United States, including investor-owned systems and those of governmental agencies—Federal, Municipal and State & Local—and also rural electric cooperatives. With the switch to the new data source in the 1981 Annual Electric Power Survey, blow-up factors formerly used to expand the sum of the nine regions to values entitled "Total Electric Utility Industry of the Contiguous United States" were no longer considered necessary and therefore were dropped.

The reported data include some industrial power installations whose operations are coordinated with the utility systems with which they are interconnected and which thereby contribute to the public supply. The data do not include any isolated industrial or institutional power installations.

Data pertaining to power system capabilities, loads, capability margins, kilowatt-hour requirements and fuel data are presented for each of the nine reliability councils of NERC. Boundaries of the nine reliability councils are shown by the map in Fig. 1. The North American Electric Reliability Council encompasses essentially all utility systems in the United States and five Canadian provinces, but the data presented in this survey cover only the systems in the contiguous United States. Summations of these regional data are presented and referred to as "Survey Totals for the Nine Regions."

Part II of this report presents the results of the quarterly survey on the manufacture and scheduling of heavy electric power equipment made as of April 1, 1983, by the Electric Power Survey Committee of the Edison Electric Institute in cooperation with representatives of the electric power systems or power areas throughout the contiguous United States, with the nation's principal manufacturers of heavy electric power equipment, and with those foreign manufacturers supplying electric generating equipment to U.S. electric power systems.

The Electric Power Survey Committee is the only group servicing the electric utility and allied industries that conducts surveys on the manufacture and scheduling of heavy electric power equipment on a quarterly basis. These quarterly surveys are also unique in that information on each planned project is cross checked with both the manufacturer and the system ordering the equipment. Furthermore, the time frame for ordered and scheduled units is not limited to ten years, but extends into the future as far out as equipment is officially ordered and scheduled for installation. The resulting data file also allows the quarterly tracking of unit slippages and cancellations.

Projections presented in this report are based on the best information available as of April 1, 1983. There could, however, be delays in the installation of scheduled capability and reductions in the capability margins based on the scheduled capability. This may occur due to the inability of utilities to secure the financing necessary to sustain the construction of new generating capacity. The delay or denial of necessary rate increases, the cost of complying with continually changing regulations, and escalating fuel costs could also adversely affect the financial condition of the industry. Furthermore, the capability of generating units now operational could be restricted due to fuel availability problems or environmental operating requirements. It is essential that the installation of both nuclear and coal-fired generating units proceed as currently scheduled and that conservation and load management programs be pursued at the same time to assure an adequate bulk electric power supply in the 1980s.

Definitions of the terms used in this report, together with information concerning methods of summarizing the data, appear on the following page.

DEFINITIONS AND METHODS OF SUMMARIZATION

Capability of the power systems, as used herein, is equivalent to Planned Resources, defined by the North American Electric Reliability Council to include "the total installed generating capacity which is existing, presently under construction, or in various stages of planning; plus scheduled capacity purchases, less capacity sales; less total generating capacity out of service in deactivated shutdown status."

This capability must provide for scheduled maintenance, emergency outages, and system operating requirements, in addition to the estimated load and any unforeseen load.

The capability of existing installations is determined by the net dependable capacity at the time of the peak load and the kilowatt-hour requirements of the system. Estimated capabilities of these systems served wholly or in part by hydraulic power sources are determined for adverse hydro conditions.

The capabilities of all systems normally interconnected are based upon fully coordinated operation. Peak capability refers to the maximum capability, as defined above, at the approximate time and for the duration of the load referred to, that is, at the time of the summer peak load or the winter peak load.

Regional capability, as reported herein, is the sum of the capabilities of the systems serving the region.

Peak Load is the maximum load encountered on the system during a given period of time.

Regional summer and winter peak loads represent the non-coincident maximum loads occurring during these two seasons.

Regional peak loads as reported herein are the sum of the peak loads on the systems serving the region, less demands which are interruptible by contract.

Capability Margin is the difference between net system capability and system maximum load requirements (peak load). It is the margin of capability available to provide for scheduled maintenance, emergency outages, system operating requirements, and unforeseen loads. On a regional or national basis, it is the difference between aggregate net system capability of the various systems in the region or nation and the sum of system maximum (peak) loads without allowance for time diversity between the loads of the several systems. However, within a region account is taken of diversity between peak loads of systems that are operated as a closely coordinated power pool.

PART I/ELECTRIC POWER SUPPLY

SUMMER PEAK CAPABILITIES, PEAK LOADS, AND CAPABILITY MARGINS

Summer peak capabilities, peak loads, and capability margins as recorded for the years 1981 and 1982, and as now forecast for the years 1983 through 1992, on the basis of adverse hydro conditions, are shown in Table 1, page 6. Similar information for winter is shown in Table II, page 8.

Fig. 2, page 10, is a graphic presentation of the summer situation for the total electric utility industry of the contiguous United States during the period 1954 through 1982. The chart also includes the present forecasts for the summer of the years 1983 through 1992 based on adverse hydro conditions.

NERC does not collect or publish historical values for capability at time of summer peak load analagous to NERC's summer planned resources series. Therefore, the historical capability margins shown in Table 1 are derived from a combination of capability at time of summer peak from the Committee's own Post-Summer Electric Power Surveys with the revised actual summer peak values reported by NERC.

SUMMER CAPABILITIES

Except for MAAC, SPP, and WSCC through 1987, the summer capability forecasts shown by this survey are generally below the values indicated in the 1982 Annual Survey of last April. For the nine regions taken together, reductions range from 0.6 to 3.2 percent for the years 1983 through 1991.

The 1992 summer capability for the sum of the nine regions is forecast at 724.8 million kilowatts. This represents an average annual increase of 2.3 percent for the ten-year period from the summer of 1982.

The total capability of the electric utility industry of the contiguous United States, given herein annually for summer 1982 (577.8 million kilowatts) and projected to summer 1992 (724.8 million kilowatts), consists of the following types of equipment in approximately the proportions listed below.

SUMMER CAPABILITY MIX

	1982	1992
Coal-Fired Steam Turbine-Generators	43.0%	45.0%
Oil-Fired Steam Turbine-Generators	8.3	5.4
Gas-Fired Steam Turbine-Generators	6.8	5.0
Dual-Fired Steam Turbine-Generators	10.6	7.7
Nuclear Steam Turbine-Generators	9.5	16.6
Conventional Hydro Generators	11.6	9.7
Pumped-Storage Generators	2.1	2.4
Combustion Turbine-Generators	6.9	5.7
Combined-Cycle Generators	0.9	0.7
Geothermal Turbine-Generators and other	0.3	1.8
	100.0%	100.0%

SUMMER PEAK LOADS

Preliminary figures published in the 1982 Post-Summer Electric Power Survey indicated that the 1982 summer peak load was 2.7 percent below 1981. According to final data now available, the actual decrease in the 1982 summer peak load was 3.1 percent.

All summer peak load forecasts have been reduced by every reliability council. For the nine regions taken together, reductions range from 3.1 percent to 4.3 percent for the years 1983 through 1991, compared with values shown for those years in the April 1982 Survey.

The summer peak load for the sum of the nine regions, which was 414.9 million kilowatts in 1982, is forecast to reach 436.2 million kilowatts in 1983, an increase of 5.1 percent. For the summer of 1992, the forecast is 558.2 million kilowatts. This is an average annual increase of 3.0 percent for the ten-year period from the summer of 1982.

SUMMER CAPABILITY MARGINS

Of the 81 summer capability margin percentages shown for the ten-year period 1983-1991 for the nine reliability councils, 70 of the values are higher than those in the April Survey of a year ago, and 11 of the percent margins are lower. MAAC, ECAR, MAIN, SPP, and MAPP show consistently higher margins from 1983 through 1991, while SERC, ERCOT and WSCC show more increases than reductions for the same period. NPCC is the only region showing more reductions than increases in projected capability margin.

Summer capability margins for the country as a whole are higher from 1983 through 1991 generally because peak load projections have been reduced more than expected capabilities. As now forecast, the summer capability margins for the country range from 37.9 percent in 1985 to 29.8 percent in 1992, shown in these surveys for the first time.

Table I SUMMER CAPABILITIES, PEAK LOADS, AND RESERVE MARGINS (Thousands of Kilowatts)

Regions		Actual 1981	1982	% Inc	1983	% Inc	1984	% Inc	1985	% Inc
NPCC	Capability Scheduled	51,752	50,400	2.6–	51,214	1.6	53,075	3.6	54,911	3.5
	Peak Load	35,640	36,427	2.2	36,065	1.0–	36,825	2.1	37,385	1.5
	Capability Margin	16,112	13,973		15,149		16,250		17,526	
	Capability Margin, %	45.2	38.4		42.0		44.1		46.9	
MAAC	Capability Scheduled	44,962	45,796	1.9	46,856	2.3	48,048	2.5	49,428	2.9
	Peak Load	33,633	33,846	0.6	34,080	0.7	34,730	1.9	35,340	1.8
	Capability Margin	11,329	11,950		12,776		13,318		14,088	
	Capability Margin, %	33.7	35.3		37.5		38.3		39.9	
ECAR	Capability Scheduled	89,902	89,489	0.5–	87,844	1.8–	93,042	5.9	96,571	3.8
	Peak Load	64,150	59,668	7.0–	62,170	4.2	64,570	3.9	68,360	5.9
	Capability Margin	25,752	29,821		25,674		28,742		28,211	
	Capability Margin, %	40.1	50.0		41.3		44.1		41.3	
SERC	Capability Scheduled	113,775	120,749	6.1	124,991	3.5	128,544	2.8	131,570	2.4
	Peak Load	90,513	86,229	4.7–	93,048	7.9	95,106	2.2	98,237	3.3
	Capability Margin	23,262	34,520		31,943		33,438		33,333	
	Capability Margin, %	25.7	40.0		34.3		35.2		33.9	
MAIN	Capability Scheduled	41,104	41,145	0.1	42,751	3.9	44,069	3.1	46,766	6.1
	Peak Load	32,561	31,394	3.6	32,773	4.4	33,741	3.0	34,707	2.9
	Capability Margin	8,543	9,751		9,978		10,328		12,059	
	Capability Margin, %	26.2	31.1		30.4		30.6		34.7	
SPP	Capability Scheduled	55,889	57,519	2.9	60,718	5.6	63,347	4.3	66,765	5.4
	Peak Load	44,623	43,064	3.5–	45,733	6.2	47,487	3.8	49,179	3.6
	Capability Margin	11,266	14,455		14,985		15,860		17,586	
	Capability Margin, %	25.2	33.6		32.8		33.4		35.8	
ERCOT	Capability Scheduled	42,080	42,529	1.1	44,405	4.4	44,688	0.6	45,939	2.8
	Peak Load	32,535	33,231	2.1	34,695	4.4	36,231	4.4	37,592	3.8
	Capability Margin	9,545	9,298		9,710		8,457		8,347	
	Capability Margin, %	29.3	28.0		28.0		23.3		22.2	
MAPP	Capability Scheduled	28,200	28,200	0.0	28,680	1.7	29,571	3.1	29,633	0.2
	Peak Load	18,985	19,470	2.6	20,893	7.3	21,496	2.9	22,409	4.2
	Capability Margin	9,215	8,730		7,787		8,075		7,224	
	Capability Margin, %	48.5	44.8		37.3		37.6		32.2	
WSCC	Capability Scheduled	104,392	102,000	2.3–	108,456	6.3	115,595	6.6	120,631	4.4
	Peak Load	75,655	71,580	5.4–	76,771	7.3	80,114	4.4	82,373	2.8
	Capability Margin	28,737	30,420		31,685		35,481		38,258	
	Capability Margin, %	38.0	42.5		41.3		44.3		46.4	
Survey Totals for the Nine Regions— Summer	Capability Scheduled	572,056	577,827	1.0	595,915	3.1	619,979	4.0	642,214	3.6
	Annual Increase		5,771		18,088		24,064		22,235	
	Peak Load	428,295	414,909	3.1–	436,228	5.1	450,300	3.2	465,582	3.4
	Annual Increase		13,386–		21,319		14,072		15,282	
	Capability Margin	143,761	162,918		159,687		169,679		176,632	
	Capability Margin, %	33.6	39.3		36.6		37.7		37.9	

1986	% Inc	1987	% Inc	1988	% Inc	1989	% Inc	1990	% Inc	1991	% Inc	1992	% Inc
55,931	1.9	57,862	3.5	57,538	0.6–	57,636	0.2	59,291	2.9	59,403	0.2	59,067	0.6–
37,755	1.0	38,355	1.6	39,075	1.9	39,825	1.9	40,475	1.6	41,185	1.8	41,905	1.7
18,176		19,507		18,463		17,811		18,816		18,218		17,162	
48.1		50.9		47.3		44.7		46.5		44.2		41.0	
49,641	0.4	50,449	1.6	50,712	0.5	51,495	1.5	52,200	1.4	51,230	1.9–	51,803	1.1
35,890	1.6	36,440	1.5	37,110	1.8	37,800	1.9	38,450	1.7	39,050	1.6	39,630	1.5
13,751		14,009		13,602		13,695		13,750		12,180		12,173	
38.3		38.4		36.7		36.2		35.8		31.2		30.7	
98,970	2.5	102,094	3.2	103,925	1.8	104,438	0.5	105,760	1.3	106,930	1.1	107,680	0.7
70,257	2.8	72,160	2.7	74,440	3.2	76,541	2.8	78,314	2.3	80,180	2.4	82 076	2.4
28,713		29,934		29,485		27,897		27,446		26,750		25,604	
40.9		41.5		39.6		36.4		35.1		33.4		31.2	
135,028	2.6	140,415	4.0	143,570	2.2	147,621	2.8	148,345	0.5	150,389	1.4	152,782	1.6
100,657	2.5	103,881	3.2	106,845	2.9	109,792	2.8	112,962	2.9	116,414	3.1	119,331	2.5
34,371		36,534		36,725		37,829		35,383		33,975		33,451	
34.1		35.2		34.4		34.5		31.3		29.2		28.0	
48,990	4.8	50,100	2.3	49,804	0.6–	49,822	0.0	49,856	0.1	49,912	0.1	49,733	0.4–
35,410	2.0	36,104	2.0	36,794	1.9	37,516	2.0	38,186	1.8	38,922	1.9	39,627	1.8
13,580		13,996		13,010		12,306		11,670		10,990		10,106	
38.4		38.8		35.4		32.8		30.6		28.2		25.5	
68,285	2.3	68,641	0.5	69,596	1.4	70,972	2.0	72,912	2.7	73,745	1.1	74,941	1.6
50,680	3.1	52,216	3.0	53,748	2.9	55,350	3.0	56,831	2.7	58,335	2.6	59,999	2.8
17,605		16,425		15,848		15,622		16,081		15,410		14,942	
34.7		31.5		29.5		28.2		28.3		26.4		24.9	
47,977	4.4	50,142	4.5	51,745	3.2	55,537	7.3	56,200	1.2	57,830	2.9	60,092	3.9
39,094	4.0	40,616	3.9	42,448	4.5	44,329	4.4	46,210	4.2	47,992	3.9	49,960	4.1
8,883		9,526		9,297		11,208		9,990		9,838		10,132	
22.7		23.5		21.9		25.3		21.6		20.5		20.3	
30,083	1.5	30,152	0.2	31,052	3.0	31,819	2.5	31,840	0.1	32,778	3.0	32,824	0.1
22,993	2.6	23,567	2.5	24,139	2.4	24,689	2.3	25,321	2.6	25,870	2.2	26,520	2.5
7,090		6,585		6,913		7,130		6,519		6,908		6,304	
30.8		27.9		28.6		28.9		25.8		26.7		23.8	
121,235	0.5	124,987	3.1	126,281	1.0	127,864	1.3	129,723	1.5	134,660	3.8	135,900	0.9
84,601	2.7	87,446	3.4	90,057	3.0	92,548	2.8	94,758	2.4	96,957	2.3	99,193	2.3
36,634		37,541		36,224		35,316		34,965		37,703		36,707	
43.3		42.9		40.2		38.2		36.9		38.9		37.0	
656,140	2.2	674,842	2.9	684,223	1.4	697,204	1.9	706,127	1.3	716,877	1.5	724,822	1.1
13,926		18,702		9,381		12,981		8,923		10,750		7,945	
477,337	2.5	490,785	2.8	504,656	2.8	518,390	2.7	531,507	2.5	544,905	2.5	558,241	2.4
11,755		13,448		13,871		13,734		13,117		13,398		13,336	
178,803		184,057		179,567		178,814		174,620		171,972		166,581	
37.5		37.5		35.6		34.5		32.9		31.6		29.8	

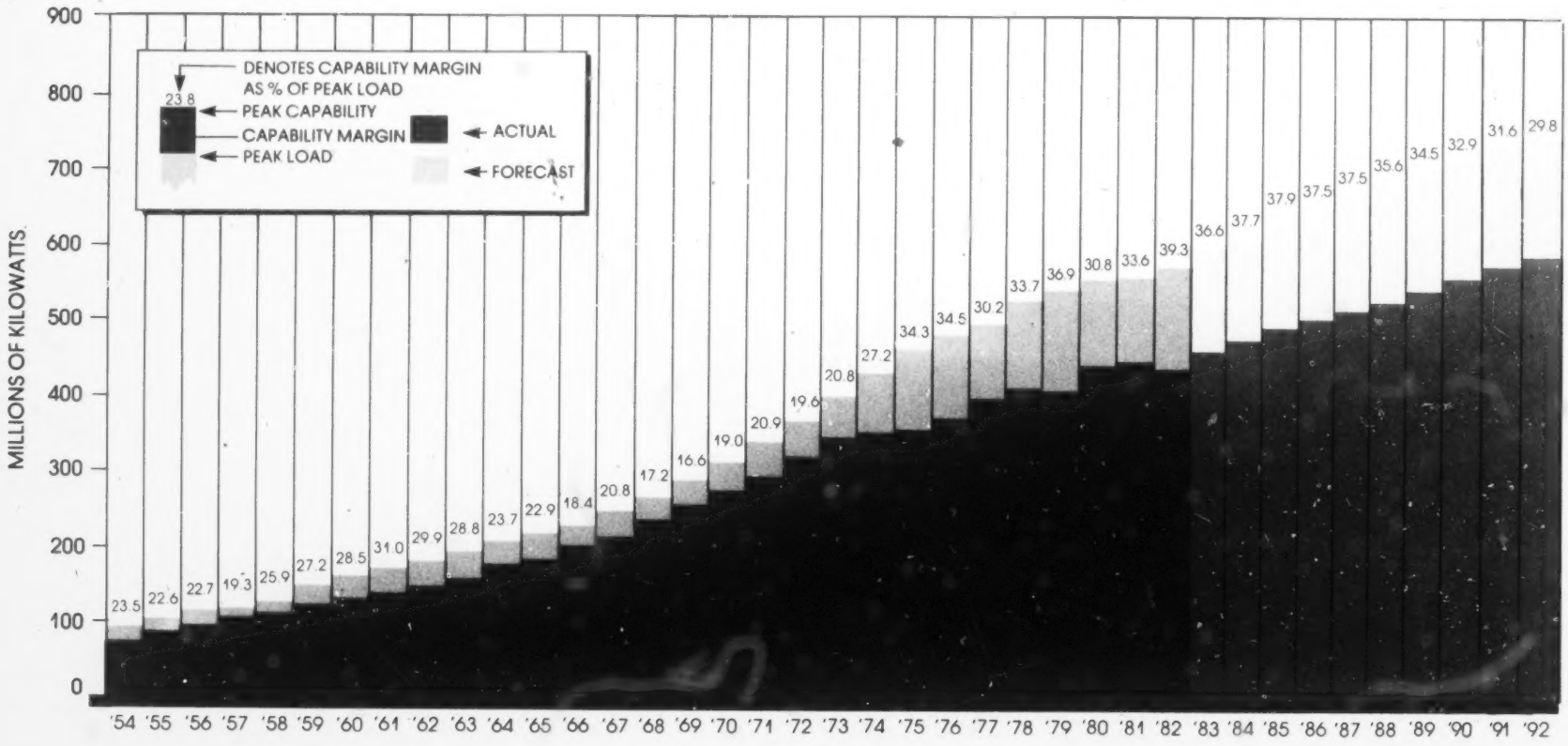
Table II WINTER CAPABILITIES, PEAK LOADS, AND RESERVE MARGINS (Thousands of Kilowatts)

Regions		Actual 1981/82	1982/83	% Inc	1983/84	% Inc	1984/85	% Inc	1985/86	% Inc
NPCC	Capability Scheduled	53,060	N.R.*		53,036		55,702	5.0	55,603	0.2–
	Peak Load	35,199	34,755	1.3–	35,255	1.4	36,105	2.4	36,585	1.3
	Capability Margin	17,861			17,781		19,597		19,018	
	Capability Margin, %	50.7			50.4		54.3		52.0	
MAAC	Capability Scheduled	46,567	N.R.*		50,030		51,565	3.1	51,870	0.6
	Peak Load	30,726	28,197	8.2–	30,260	7.3	30,980	2.4	31,680	2.3
	Capability Margin	15,841			19,770		20,585		20,190	
	Capability Margin, %	51.6			65.3		66.4		63.7	
ECAR	Capability Scheduled	91,731	N.R.*		92,641		98,216	6.0	99,293	1.1
	Peak Load	63,188	56,559	10.5–	62,992	11.4	67,129	6.6	69,249	3.2
	Capability Margin	28,543			29,649		31,087		30,044	
	Capability Margin, %	45.2			47.1		46.3		43.4	
SERC	Capability Scheduled	122,379	N.R.*		128,679		131,063	1.9	135,920	3.7
	Peak Load	93,348	85,664	8.2–	92,662	8.2	95,469	3.0	97,860	2.5
	Capability Margin	29,031			36,017		35,594		38,060	
	Capability Margin, %	31.1			38.9		37.3		38.9	
MAIN	Capability Scheduled	41,596	N.R.*		43,558		45,907	5.4	49,785	8.4
	Peak Load	26,965	24,303	9.9–	27,499	13.2	28,249	2.7	29,105	3.0
	Capability Margin	14,631			16,059		17,658		20,680	
	Capability Margin, %	54.3			58.4		62.5		71.1	
SPP	Capability Scheduled	54,004	N.R.*		61,291		63,393	3.4	66,772	5.3
	Peak Load	32,087	32,743	2.0–	34,602	5.7	36,014	4.1	37,316	3.6
	Capability Margin	21,917			26,689		27,379		29,456	
	Capability Margin, %	68.3			77.1		76.0		78.9	
ERCOT	Capability Scheduled	40,627	N.R.*		44,401		45,814	3.2	46,080	0.6
	Peak Load	25,393	25,347	0.2–	26,558	4.8	27,792	4.6	28,591	2.9
	Capability Margin	15,234			17,843		18,022		17,489	
	Capability Margin, %	60.0			67.2		64.8		61.2	
MAPP	Capability Scheduled	28,651	N.R.*		29,290		29,604	1.1	29,724	0.4
	Peak Load	17,508	17,816	1.8	18,255	2.5	18,775	2.8	19,732	5.1
	Capability Margin	11,143			11,035		10,829		9,992	
	Capability Margin, %	63.6			60.5		57.7		50.6	
WSCC	Capability Scheduled	102,469	N.R.*		112,763		116,424	3.2	119,723	2.8
	Peak Load	66,692	67,934	1.9	74,880	10.2	77,823	3.9	79,981	2.8
	Capability Margin	35,777			37,883		38,601		39,742	
	Capability Margin, %	53.6			50.6		49.6		49.7	
Survey Totals for the Nine Regions— Winter	Capability Scheduled	581,084	N.R.*		615,689		637,688	3.6	654,770	2.7
	Annual Change				23,689		21,999		17,082	
	Peak Load	391,106	373,318	4.5–	402,963	7.9	418,336	3.8	430,099	2.8
	Annual Change		17,788–		29,645		15,373		11,763	
	Capability Margin	189,978			212,726		219,352		224,671	
	Capability Margin, %	48.6			52.8		52.4		52.2	

*N.R. – Not Reported

1986/87	% Inc	1987/88	% Inc	1988/89	% Inc	1989/90	% Inc	1990/91	% Inc	1991/92	% Inc	1992/93	% Inc
56,843	2.2	58,442	2.8	58,335	0.2–	59,257	1.6	60,281	1.7	59,987	0.5–	59,858	0.2–
36,925	0.9	37,465	1.5	38,265	2.1	39,065	2.1	39,825	1.9	40,665	2.1	41,485	2.0
19,918		20,977		20,070		20,192		20,456		19,322		18,373	
53.9		56.0		52.5		51.7		51.4		47.5		44.3	
51,908	0.1	52,814	1.7	54,117	2.5	53,804	0.6–	53,496	0.6–	53,031	0.9–	53,439	0.8
32,580	2.8	33,490	2.8	34,390	2.7	35,270	2.6	36,090	2.3	36,880	2.2	37,570	1.9
19,328		19,324		19,727		18,534		17,406		16,151		15,869	
59.3		57.7		57.4		52.5		48.2		43.8		42.2	
103,476	4.2	103,071	0.4–	105,870	2.7	106,793	0.9	108,571	1.7	109,231	0.6	110,675	1.3
71,159	2.8	73,511	3.3	75,893	3.2	77,875	2.6	79,870	2.6	81,921	2.6	83,999	2.5
32,317		29,560		29,977		28,918		28,701		27,310		26,676	
45.4		40.2		39.5		37.1		35.9		33.3		31.7	
138,737	2.1	144,736	4.3	146,265	1.1	149,453	2.2	150,180	0.5	152,370	1.5	154,736	1.6
100,940	3.1	104,152	3.2	106,825	2.6	109,827	2.8	113,265	3.1	116,435	2.8	119,253	2.4
37,797		40,584		39,440		39,626		36,915		35,935		35,483	
37.4		39.0		36.9		36.1		32.6		30.9		29.8	
50,925	2.3	50,934	0.0	50,639	0.6–	50,622	0.0–	50,694	0.1	50,549	0.3–	50,521	0.1–
29,886	2.7	30,700	2.7	31,549	2.8	32,339	2.5	33,176	2.6	34,011	2.5	34,814	2.4
21,039		20,234		19,090		18,283		17,518		16,538		15,707	
70.4		65.9		60.5		56.5		52.8		48.6		45.1	
67,906	1.7	67,431	0.7–	70,058	3.9	70,894	1.2	71,713	1.2	72,837	1.6	73,489	0.9
38,488	3.1	39,739	3.3	40,990	3.1	42,222	3.0	43,548	3.1	44,915	3.1	46,294	3.1
29,418		27,692		29,068		28,672		28,165		27,922		27,195	
76.4		69.7		70.9		67.9		64.7		62.2		58.7	
48,005	4.2	50,306	4.8	52,330	4.0	56,058	7.1	56,488	0.8	57,750	2.2	61,418	6.4
29,834	4.3	31,264	4.8	32,823	5.0	34,479	5.0	36,025	4.5	37,617	4.4	39,272	4.4
18,171		19,042		19,507		21,579		20,463		20,133		22,146	
60.9		60.9		59.4		62.6		56.8		53.5		56.4	
29,988	0.9	30,544	1.9	31,674	3.7	31,666	0.0–	32,096	1.4	32,626	1.7	32,810	0.6
20,145	2.1	20,565	2.1	21,033	2.3	21,498	2.2	22,003	2.3	22,561	2.5	23,212	2.9
9,843		9,979		10,641		10,168		10,093		10,065		9,598	
48.9		48.5		50.6		47.3		45.9		44.6		41.3	
123,730	3.3	125,950	1.8	127,123	0.9	129,455	1.8	131,652	1.7	135,940	3.3	136,747	0.6
82,952	3.7	85,912	3.6	88,323	2.8	90,810	2.8	92,973	2.4	95,097	2.3	95,473	0.4
40,778		40,038		38,800		38,645		38,679		40,843		41,274	
49.2		46.6		43.9		42.6		41.6		42.9		43.2	
671,518	2.6	684,228	1.9	696,411	1.8	708,002	1.7	715,171	1.0	724,321	1.3	733,693	1.3
16,748		12,710		12,183		11,591		7,169		9,150		9,372	
442,909	3.0	456,798	3.1	470,091	2.9	483,385	2.8	496,775	2.8	510,102	2.7	521,372	2.2
12,810		13,889		13,293		13,294		13,390		13,327		11,270	
228,609		227,430		226,320		224,617		218,396		214,219		212,321	
51.6		49.8		48.1		46.5		44.0		42.0		40.7	

Fig. 2 SUMMER PEAK CAPABILITIES, PEAK LOADS, AND CAPABILITY MARGINS
Total Electric Utility Industry of the Contiguous United States



WINTER PEAK CAPABILITIES, PEAK LOADS, AND CAPABILITY MARGINS

WINTER CAPABILITIES

The Annual Electric Power Survey of April 1976 was the first report to show data for the turn-of-the-year, winter season rather than specifically for the month of December. The December series has been maintained since then in the Year-End Electric Power Surveys.

The actual winter 1982/83 capability for the sum of the nine regions of the contiguous United States cannot be calculated because the actual installed capability for the winter season was not collected by NERC.

Winter 1983/84 capability now forecast for the entire electric utility industry under adverse hydro conditions is 615.7 million kilowatts. The new forecasts for 1983/84 through 1991/92 for the nine regions taken together show reduced values, ranging from 0.5 percent to 3.3 percent below the winter capabilities expected for these years twelve months ago.

For winter 1992/1993, shown in these surveys for the first time, the total capability of the industry under adverse hydro conditions is forecast to reach 733.7 million kilowatts.

Table IX summarizes the generating capacity additions placed in commercial operation during the first three months of 1983, with the exception of combined-cycle generators, according to the same equipment type classifications as contained in the capability mix table shown in the summer text on page 5. Table X shows similar data for all scheduled generating additions through 1989 and later.

WINTER PEAK LOADS

According to actual operating records now available, the winter 1982/83 peak load for the sum of the nine regions of the contiguous United States was 373.3 million kilowatts—17.8 million kilowatts, or 4.5 percent, below the winter 1981/82 peak load.

As now forecast, the winter 1983/84 peak load for the country will reach 403.0 million kilowatts, an increase of 7.9 percent over the winter 1982/83 peak load. For winter 1992/93, shown in these surveys for the first time, the forecast peak load is 521.4 million kilowatts. This represents an average annual increase during the ten-year period from winter 1982/83 of 3.4 percent.

WINTER CAPABILITY MARGINS

Compared with winter capability margins forecast one year ago, regional winter margins reported in this survey are generally higher for all reliability councils except ERCOT. For the country as a whole, capability margins are now forecast to range from 52.8 percent for the winter of 1983/84 to 40.7 percent for 1992/93, shown in these surveys for the first time.

RELATIONSHIP BETWEEN SUMMER AND WINTER PEAK LOADS

The relationship between the summer and winter peak loads in the different regions of the country, and also for the contiguous United States, are shown in Table III, where the summer peak load in each case is expressed as a percentage of the winter peak load for the following season.

In those regions where the summer peak load has been characteristically higher then the peak during the following winter, the percentage figure has, expectedly, been above 100 percent. This has been true in particular in SPP and ERCOT, where, due to climatic conditions, heavy air conditioning loads during the summer months have caused peaks that far exceed those during the following winter.

In these regions it has not been possible to develop electric heating loads during the winter months to offset the heavy air conditioning load in summer.

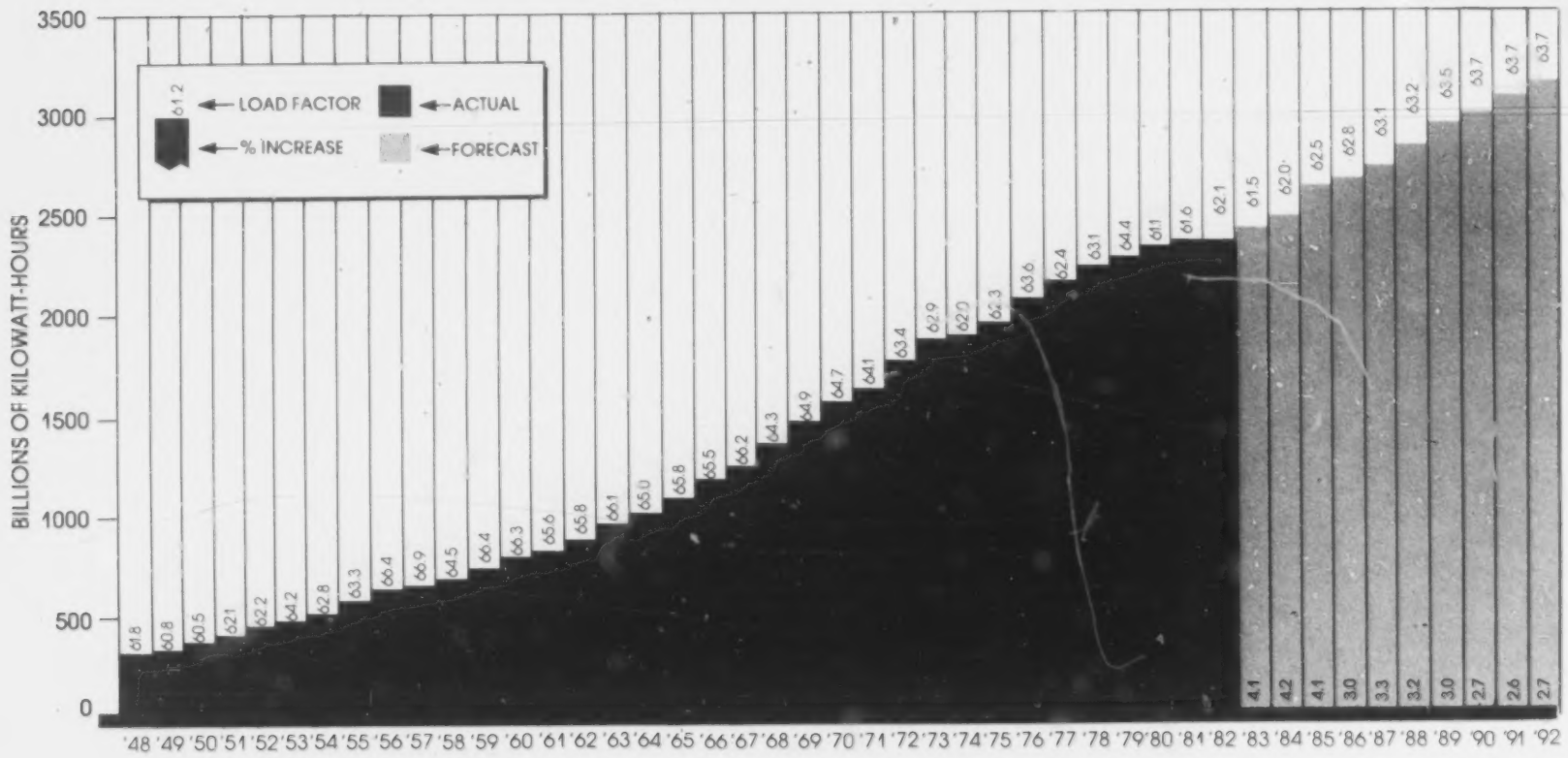
From the 1950s through the early 1970s there was a gradual trend in most regions for the summer peak load to approach and then exceed the peak of the following winter. The last year in which the country as a whole experienced a summer peak that was about the same as the winter peak load was 1963. During the years 1964 through 1971, there was a departure from the equality of summer and winter peaks experienced in the early 1960s. Since 1964 summer peaks have generally exceeded the peaks for the following winter by increasing amounts. In 1970, and again in 1971, apparently normal summer peaks were followed by winter peaks depressed both by mild weather and reduced industrial loads. This combination produced summer to winter peak relationships of 111 percent and 112 percent respectively in 1970 and 1971.

After falling back to 110 percent in 1972, the summer/winter ratio jumped to a high of 119 percent in 1973 because of the unprecedented drop in the winter peak load from the year previous. The ratio lowered only one point in 1974 since both the summer and winter peak loads were little changed from those experienced in 1973. The relationship between the summer and winter peaks dropped back to more normal values of 108 percent and 106 percent, respectively, in 1975 and 1976. This was followed by a rise to 110 percent in 1977, a decline to 107 percent in 1978, and an uptick to 108 percent in 1979. The hot summer of 1980 and the economic downturn of 1981 helped to produce values of 111 and 110 respectively. In 1982 the summer peak dropped 3.1 percent and the winter peak dropped 4.5 percent. The greater relative decline in the winter peak caused the summer/winter ratio to increase to 111 in 1982. The forecast now projects a constant 108 percent from 1983 to 1986, followed by a six-year plateau at 107 percent through 1992.

Table III SUMMER PEAK LOADS EXPRESSED AS PERCENTAGE OF PEAK LOAD FOR THE FOLLOWING WINTER

	ACTUAL								FORECAST									
Regions	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992
NPCC	102	96	105	102	100	104	101	105	102	102	102	102	102	102	102	102	101	101
MAAC	114	108	115	111	114	116	109	120	113	112	112	110	109	108	107	107	106	105
ECAR	102	97	101	99	104	101	102	105	99	96	99	99	98	98	98	98	98	98
SERC	100	93	99	99	101	99	97	101	100	100	100	100	100	100	100	100	100	100
MAIN	119	122	122	118	123	127	121	129	119	119	119	118	118	117	116	115	114	114
SPP	124	144	144	138	133	147	139	132	132	132	132	132	131	131	131	131	130	130
ERCOT	141	142	148	134	130	132	128	131	131	130	131	131	130	129	129	128	128	127
MAPP	106	103	111	111	105	111	108	109	114	114	114	114	115	115	115	115	115	114
WSCC	104	107	105	98	100	107	113	105	103	103	103	102	102	102	102	102	102	104
Survey Totals for the Nine Regions	108	106	110	107	108	111	110	111	108	108	108	108	107	107	107	107	107	107

Fig. 3 ANNUAL KILOWATT-HOUR REQUIREMENTS AND ANNUAL LOAD FACTORS
Total Electric Utility Industry of the Contiguous United States



KILOWATT-HOUR REQUIREMENTS AND ANNUAL LOAD FACTORS

Calendar-year kilowatt-hour requirements by region and for the total of the lower forty-eight states are shown in Table IV. The corresponding annual load factors are given in Table V. The kilowatt-hour requirement represents utility generation plus kilowatt-hours received from all outside sources, including net imports from other countries and energy from certain industrial installations which are interconnected and coordinated with the utility systems.

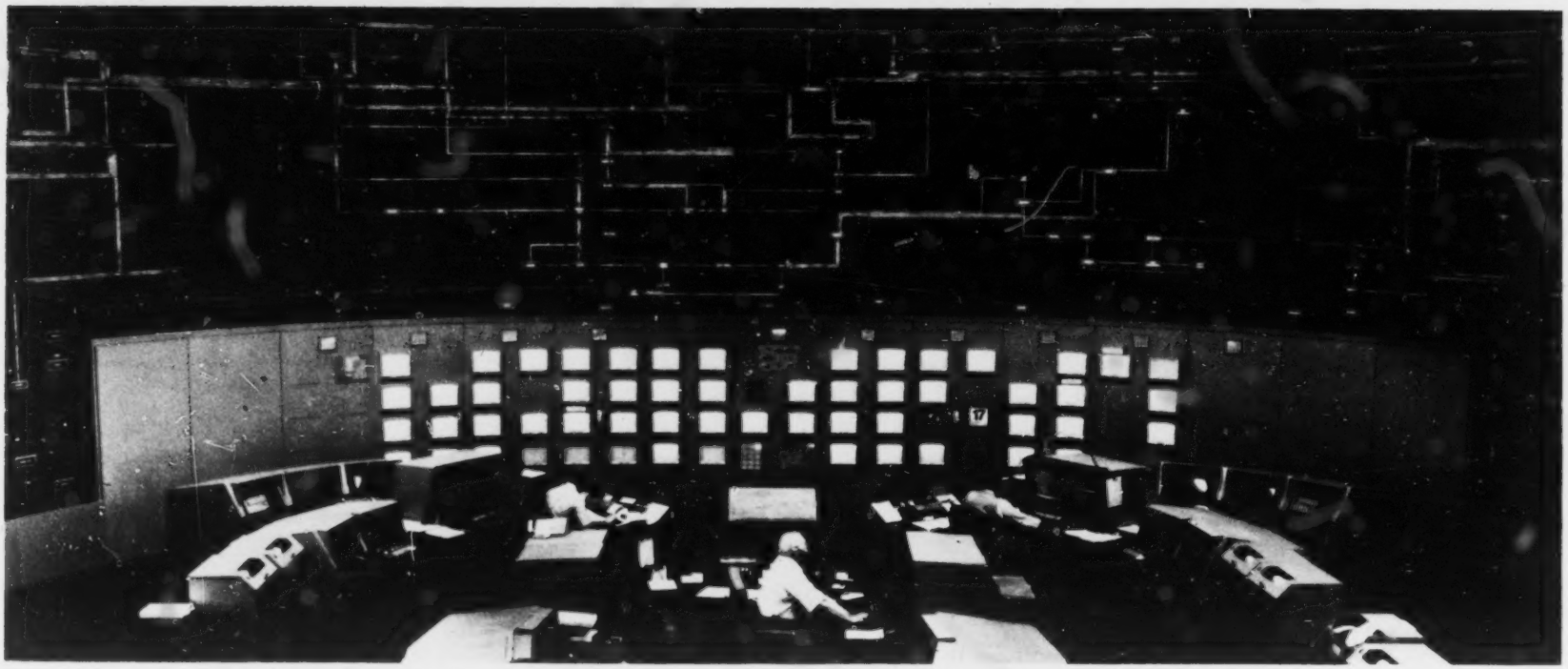
The present forecasts of kilowatt-hour requirements for the contiguous United States for the years 1983 through 1991 range between 5.0 and 3.7 percent below the values predicted in the previous survey of Aprii 1, 1982. For 1992, shown in these surveys for the first time, the projected kilowatt-hour requirement is 3.1 trillion kilowatt-hours. The average annual increase in kilowatt-hour requirements during the ten-year period 1983 through 1992, according to present forecasts, is 3.3 percent.

Fig. 3, Page 13, is a bar chart showing the total annual kilowatt-hour requirements for the entire industry, starting with the year 1948 and including the forecasts for the years 1983 through 1992. Annual load factors are printed at the top of each bar. The average annual increase in kwhr requirements for the entire period shown in Fig. 3 is 5.7 percent.

Table IV ANNUAL KILOWATT-HOUR REQUIREMENTS—MILLIONS as of April 1, 1983

Regions	1981*	1982*	% Chg	1983	% Chg	1984	% Chg	1985	% Chg	1986	% Chg
NPCC	202,620	201,377	0.6–	204,159	1.4	208,245	2.0	212,270	1.9	214,870	1.2
MAAC	174,668	171,662	1.7–	175,464	2.2	180,646	3.0	185,173	2.5	189,214	2.2
ECAR	366,376	347,091	5.3–	361,100	4.0	378,800	4.9	404,100	6.7	415,000	2.7
SERC	483,595	466,832	3.5–	492,507	5.5	509,047	3.4	530,495	4.2	547,381	3.2
MAIN	162,899	158,116	2.9–	164,610	4.1	170,171	3.4	175,674	3.2	179,758	2.3
SPP	211,833	211,595	0.1–	218,738	3.4	230,490	5.4	238,369	3.4	246,929	3.6
ERCOT	164,920	169,769	2.9	178,023	4.9	187,354	5.2	193,766	3.4	201,032	3.7
MAPP	96,307	96,992	0.7	102,656	5.8	108,120	5.3	113,749	5.2	117,911	3.7
WSCC	447,788	435,310	2.8–	454,125	4.3	477,529	5.2	497,110	4.1	515,005	3.6
Survey Totals for the Nine Regions	2,311,006	2,258,744	2.3–	2,351,382	4.1	2,450,402	4.2	2,550,706	4.1	2,627,100	3.0
Annual Increase		52,262–		92,638		99,020		100,304		76,394	

*Actual



1987	% Chg	1988	% Chg	1989	% Chg	1990	% Chg	1991	% Chg	1992	% Chg
218,358	1.6	223,151	2.2	228,371	2.3	233,034	2.0	238,006	2.1	243,057	2.1
192,944	2.0	197,174	2.2	201,370	2.1	205,435	2.0	209,159	1.8	212,779	1.7
426,300	2.7	440,200	3.3	452,600	2.8	462,700	2.2	473,400	2.3	486,300	2.7
568,395	3.8	587,755	3.4	606,650	3.2	625,313	3.1	643,970	3.0	662,537	3.4
184,807	2.8	188,831	2.2	193,220	2.3	197,417	2.2	201,616	2.1	205,901	2.1
254,882	3.2	262,700	3.1	270,779	3.1	278,751	2.9	286,646	2.8	295,118	3.0
209,665	4.3	220,707	5.3	231,505	4.9	242,563	4.8	252,606	4.1	262,929	4.1
121,900	3.4	125,774	3.2	129,659	3.1	133,473	2.9	137,166	2.8	140,979	2.8
536,165	4.1	554,261	3.4	571,262	3.1	584,940	2.4	599,232	2.4	613,864	2.4
2,713,416	3.3	2,800,553	3.2	2,885,416	3.0	2,963,626	2.7	3,041,801	2.6	3,123,464	2.7
86,316		87,137		84,863		78,210		78,175		81,663	

Table V ANNUAL LOAD FACTORS, %

	ACTUAL		FORECAST									
Regions	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992
NPCC	64.9	63.1	64.6	64.4	64.8	65.0	65.0	65.0	65.5	65.7	66.0	66.0
MAAC	59.3	57.9	58.8	59.2	59.8	60.2	60.4	60.5	60.8	61.0	61.1	61.1
ECAR	65.2	66.4	65.4	64.2	66.6	66.6	66.2	66.0	66.3	66.1	66.0	65.9
SERC	59.1	61.8	60.4	60.7	61.6	61.9	62.3	62.6	63.1	63.0	63.1	63.2
MAIN	57.1	57.5	57.3	57.4	57.8	58.0	58.4	58.4	58.8	59.0	59.1	59.2
SPP	54.2	56.1	54.6	55.3	55.3	55.6	55.7	55.6	55.8	56.0	56.1	56.0
ERCOT	57.9	58.3	58.6	58.9	58.8	58.7	58.9	59.2	59.6	59.9	60.1	59.9
MAPP	57.9	56.9	56.1	57.3	57.9	58.5	59.0	59.3	60.0	60.2	60.5	60.5
WSCC	67.6	69.4	67.5	67.9	68.9	69.5	70.0	70.1	70.5	70.5	70.6	70.5
Survey Totals for the Nine Regions	61.6	62.1	61.5	62.0	62.5	62.8	63.1	63.2	63.5	63.7	63.7	63.7

COMPARISON WITH PREVIOUS FUEL SURVEY

Comparison of 1983–91 Kilowatt-Hour Projections by Source, Fuels and Hydro, in April 1982 and April 1983 Electric Power Surveys

The expected relative percent share of total net generation for coal has increased from 53.1 to 54.3 percent for 1983, increased from 51.8 to 53.1 percent for 1984, and at 52.7 percent of total in 1988 is one whole percentage point higher than in the April 1982 Survey. Shown for the first time in these surveys, the expected percent share for coal in 1992 is 54.2 percent.

While the percent share of generation accounted for by gas has a downward trend similar to that forecast a year ago, the annual percentages now start from a higher point. Projected percent share for gas for 1983 has been increased from 12.4 to 13.6 percent, has risen from 11.2 to 12.3 percent for 1984, and has gone up from 8.3 to 9.3 percent for 1988. A decline to 8.0 percent is shown by 1992.

Projected percent share for oil dropped from 6.9 to 6.1 percent for 1983, declined from 6.2 to 4.9 percent for 1984, and has been reduced from 4.9 to 3.4 percent for 1988. A slight rise to 3.9 percent is shown for 1992. These lower shares of total generation expected from oil derive at least partially from the greater availability of gas now forecast, compared to a year ago.

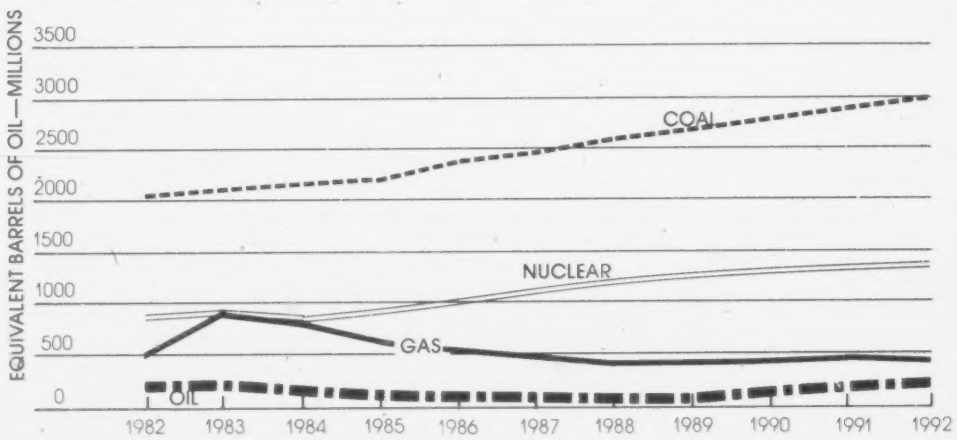
The new projections of generation from nuclear sources for the period 1983–91 are all reduced from those forecast one year ago. The expectation for the 1983 share has dropped from 16.3 to 14.5 percent, from 19.5 to 18.7 percent for 1984, and from 24.5 to 24.0 percent for 1988. Nuclear is now forecast to slip to 23.7 percent of total net generation by 1992, as nuclear generation reaches a plateau in the early 1990s.

While increasing slightly over the period in terms of actual kilowatt-hours generated, hydro is expected to account for 11.1 percent of total net generation in 1983 and drop to 9.1 percent by 1992.

During the period 1983–1992, generation from other sources ranges from 0.9 to 1.9 percent and pumping energy deductions range between 0.5 and 0.8 percent.

Fig. 4

FUEL REQUIREMENTS FOR ELECTRIC GENERATION (Expressed in Oil Equivalents)



GENERATION BY SOURCE, FUELS AND HYDRO

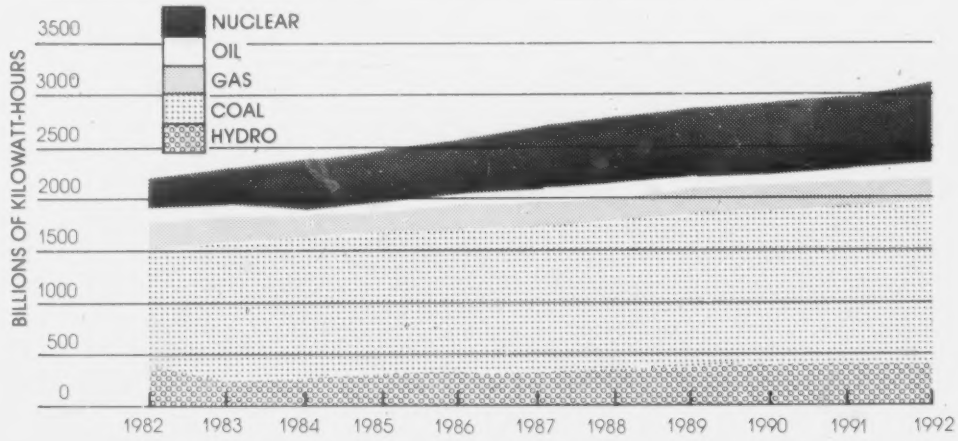


Table VI NET GENERATION BY SOURCE, FUELS AND HYDRO—MILLIONS OF KILOWATT-HOURS

	1982 Actual	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992
NPCC											
Coal	32,055	34,763	41,587	44,282	49,380	50,168	58,528	65,975	67,368	69,192	69,600
Oil	66,204	68,445	58,873	55,598	50,082	39,059	31,950	29,095	31,549	34,493	39,257
Gas	15,679	8,158	7,142	949	913	790	0	0	0	0	0
Nuclear	40,878	49,472	54,745	62,302	66,871	77,905	82,400	83,100	84,040	84,540	85,040
Hydro, adverse conditions	34,267	29,337	29,883	30,043	30,471	30,683	30,791	31,040	31,483	32,136	32,315
Other	60	232	468	684	781	781	840	889	1,030	1,133	1,133
Pumping Energy (deduct)	4,903–	2,915–	3,220–	3,320–	3,860–	3,960–	3,990–	4,260–	4,868–	5,720–	5,720–
Total Net Generation	184,240	187,492	189,478	190,538	194,638	195,426	200,519	205,839	210,602	215,774	221,625
MAAC											
Coal	85,799	87,819	89,091	89,813	88,078	89,163	89,129	91,579	87,589	91,197	94,048
Oil	15,928	15,496	10,513	8,952	7,990	7,758	7,746	7,432	6,434	7,800	11,885
Gas	6,284	6,961	5,099	4,032	3,829	3,538	3,589	2,890	3,011	2,910	722
Nuclear	37,826	43,668	53,617	58,787	66,141	68,373	72,406	75,158	84,849	83,317	81,992
Hydro, adverse conditions	4,872	4,828	5,014	5,248	5,367	5,582	5,497	5,577	5,419	5,540	5,579
Other	1,017	1,042	966	1,360	1,741	2,079	2,410	2,405	2,405	2,405	2,412
Pumping Energy (deduct)	2,362–	1,848–	2,118–	2,394–	2,391–	2,586–	2,469–	2,579–	2,358–	2,528–	2,585–
Total Net Generation	149,364	157,966	162,182	165,798	170,755	173,907	178,308	182,462	187,349	190,641	194,053
ECAR											
Coal	347,164	345,831	339,534	353,317	360,164	360,329	369,152	371,539	374,091	381,088	391,620
Oil	1,748	1,875	1,934	2,097	2,264	2,415	2,575	2,758	2,937	3,065	3,067
Gas	153	222	380	759	860	815	753	805	846	880	906
Nuclear	22,167	22,171	42,201	51,644	55,575	66,754	71,047	80,143	86,245	87,683	89,144
Hydro, adverse conditions	4,187	4,275	4,275	4,275	4,570	4,864	4,864	4,864	4,864	4,864	4,864
Other	0	0	0	0	0	0	0	0	0	0	0
Pumping Energy (deduct)	2,399–	2,927–	2,927–	2,927–	3,669–	3,810–	3,810–	3,810–	3,810–	3,810–	3,810–
Total Net Generation	373,020	371,447	385,397	409,165	419,764	431,367	444,581	456,299	465,173	473,770	485,791
SERC											
Coal	270,584	294,761	301,659	322,313	331,300	331,486	340,049	354,950	364,363	378,406	389,455
Oil	35,181	32,172	25,099	21,422	20,993	21,025	22,861	25,812	27,063	29,111	32,504
Gas	17,576	15,118	13,420	12,441	12,593	11,284	8,944	8,670	8,412	8,346	8,056
Nuclear	102,899	115,903	139,643	149,802	160,789	182,148	190,279	189,315	196,446	199,433	197,139
Hydro, adverse conditions	38,174	32,869	33,570	34,470	35,418	37,336	38,770	38,812	38,774	39,278	39,533
Other	4,345	2,290	2,689	3,271	4,299	4,522	3,643	4,531	4,639	5,070	4,979
Pumping Energy (deduct)	3,348–	3,239–	3,673–	4,412–	5,507–	7,948–	6,572–	6,541–	6,497–	7,145–	7,452–
Total Net Generation	465,411	489,874	512,407	539,307	559,885	579,853	597,974	615,549	633,200	652,499	664,214
MAIN											
Coal	105,766	113,007	107,976	105,045	102,218	103,536	105,150	107,305	110,832	113,325	114,860
Oil	4,086	4,617	3,398	2,403	1,387	1,233	1,483	2,252	2,987	3,533	4,291
Gas	759	879	543	232	191	169	166	229	288	281	413
Nuclear	35,645	39,036	53,582	66,539	76,133	78,812	79,609	80,153	79,830	80,771	81,963
Hydro, adverse conditions	2,476	2,304	2,344	2,359	2,331	2,334	2,326	2,315	2,328	2,337	2,342
Other	685	431	447	582	623	684	752	816	808	882	884
Pumping Energy (deduct)	32–	103–	160–	169–	118–	120–	105–	82–	111–	114–	124–
Total Net Generation	149,385	160,171	168,130	176,991	182,765	186,648	189,381	192,988	196,962	201,015	204,629

Table VI NET GENERATION BY SOURCE, FUELS AND HYDRO—MILLIONS OF KILOWATT-HOURS

	1982 Actual	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992
SPP											
Coal	90,508	103,473	108,653	115,437	120,860	124,685	129,405	133,042	141,318	143,736	151,125
Oil	1,355	2,709	1,864	1,840	2,651	3,463	3,884	3,261	3,423	4,571	4,797
Gas	99,271	96,734	94,492	83,250	81,817	82,469	82,383	83,185	81,469	83,150	85,151
Nuclear	7,463	11,815	21,304	24,369	31,529	33,490	37,103	39,333	40,576	41,872	41,385
Hydro, adverse conditions	5,717	5,647	5,652	5,719	5,650	5,650	5,649	5,650	5,650	5,650	5,650
Other	896	896	889	889	889	1,947	1,947	2,958	2,998	3,750	5,054
Pumping Energy (deduct)	149–	107–	117–	123–	0	0	0	0	0	0	0
Total Net Generation	205,061	221,167	232,737	231,381	243,396	251,704	260,371	267,429	275,434	282,729	293,162
ERCOT											
Coal	62,146	66,465	65,768	66,306	69,674	75,982	84,534	97,332	104,538	114,496	124,760
Oil	1,010	379	379	1,742	380	2,828	2,834	2,290	2,943	2,644	2,091
Gas	96,712	101,395	106,851	106,398	104,199	101,136	101,824	98,844	97,727	97,793	97,494
Nuclear	0	0	3,936	7,205	13,162	17,421	19,994	24,500	28,023	29,226	29,892
Hydro, adverse conditions	379	303	303	303	305	312	312	312	312	312	312
Other	0	1	4	3	5	163	319	314	340	376	412
Pumping Energy (deduct)	0	0	0	0	0	0	0	0	0	0	0
Total Net Generation	160,247	168,543	177,241	181,957	187,725	197,842	209,817	223,592	233,883	244,847	254,961
MAPP											
Coal	60,897	70,373	74,945	80,088	84,699	88,972	91,704	94,340	97,179	103,049	105,479
Oil	126	130	130	165	204	294	248	349	512	465	411
Gas	253	209	112	105	148	164	150	173	207	128	109
Nuclear	23,549	23,666	23,354	25,315	24,821	24,304	25,131	25,176	24,712	24,787	24,964
Hydro, adverse conditions	12,777	13,418	13,631	13,650	13,630	13,436	13,513	13,520	13,522	13,530	13,543
Other	0	0	0	0	0	0	0	0	0	0	0
Pumping Energy (deduct)	0	0	0	0	0	0	0	0	0	0	0
Total Net Generation	97,602	107,796	112,172	119,323	123,502	127,170	130,746	133,558	136,132	141,959	144,506
WSCC											
Coal	129,949	138,418	149,981	154,393	161,332	173,700	183,083	190,201	199,571	206,996	215,005
Oil	9,621	16,214	15,828	17,139	19,386	20,361	20,382	19,980	21,962	19,692	21,626
Gas	57,393	85,076	68,651	65,894	61,643	58,298	57,593	57,519	54,347	56,294	51,122
Nuclear	12,836	30,087	58,452	61,919	69,488	80,606	81,970	82,496	82,413	91,648	91,989
Hydro, adverse conditions	218,260	163,187	162,477	165,808	166,319	164,057	168,224	168,528	168,981	166,368	172,806
Other	6,487	14,777	17,390	21,781	24,999	28,373	30,275	34,554	37,543	39,733	41,976
Pumping Energy (deduct)	2,055–	1,249–	1,388–	1,572–	1,704–	2,153–	2,414–	2,392–	2,175–	2,244–	2,410–
Total Net Generation	432,491	446,510	471,391	485,362	501,463	523,242	539,113	550,886	562,642	578,487	592,114
TOTAL											
Coal	1,184,868	1,254,910	1,279,194	1,330,994	1,367,706	1,398,021	1,450,734	1,506,263	1,546,849	1,601,485	1,655,952
Oil	135,259	142,037	118,018	111,358	105,337	98,436	93,963	93,229	99,810	105,374	119,929
Gas	294,080	314,752	296,690	274,060	266,193	258,663	255,402	252,315	246,307	249,782	243,973
Nuclear	283,263	335,818	450,834	507,882	564,509	629,813	659,939	679,374	707,134	723,277	723,438
Hydro, adverse conditions	321,109	256,168	257,149	261,875	264,061	264,177	269,947	270,618	271,333	270,015	276,944
Other	13,490	19,669	22,853	28,570	33,337	38,549	40,186	46,467	49,763	53,349	56,850
Pumping Energy (deduct)	15,248–	12,388–	13,603–	14,917–	17,249–	20,577–	19,360–	19,664–	19,819–	21,561–	22,101–
Total Net Generation (Contiguous U.S.)	2,216,821	2,310,966	2,411,135	2,499,822	2,583,894	2,667,082	2,750,811	2,828,602	2,901,377	2,981,721	3,054,985
PERCENTAGE BY SOURCE											
Coal	53.4%	54.3%	53.1%	53.2%	52.9%	52.4%	52.7%	53.3%	53.3%	53.7%	54.2%
Oil	6.1	6.1	4.9	4.5	4.1	3.7	3.4	3.3	3.4	3.5	3.9
Gas	13.3	13.6	12.3	11.0	10.3	9.7	9.3	8.9	8.5	8.4	8.0
Nuclear	12.8	14.5	18.7	20.3	21.8	23.6	24.0	24.0	24.4	24.3	23.7
Hydro, adverse conditions	14.5	11.1	10.7	10.5	10.2	9.9	9.8	9.6	9.4	9.1	9.1
Other	0.6	0.9	0.9	1.1	1.3	1.4	1.5	1.6	1.7	1.8	1.9
Pumping Energy (deduct)	0.7–	0.5–	0.6–	0.6–	0.7–	0.8–	0.7–	0.7–	0.7–	0.7–	0.7–
Total	100.0%	100.0%	100.0%	100.0%	99.9%	99.9%	100.0%	100.0%	100.0%	100.1%	100.1%

Table VII FOSSIL REQUIREMENTS FOR ELECTRIC GENERATION IN PHYSICAL UNITS, CONTIGUOUS U.S.

	1982 Actual	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992
GROSS COAL REQUIREMENTS IN PHYSICAL UNITS—(Thousands of Tons)											
NPCC	13,008	14,438	16,550	17,612	19,844	20,054	23,831	26,929	27,449	28,204	28,314
MAAC	35,411	36,486	36,916	37,243	36,570	36,796	36,781	37,755	36,173	37,950	39,090
ECAR	154,366	162,540	159,581	166,059	169,277	169,354	173,502	174,623	175,823	179,111	184,061
SERC	113,221	123,688	125,977	135,365	138,159	138,776	140,397	145,892	151,105	156,395	160,795
MAIN	54,671	58,241	55,512	54,256	52,518	54,276	57,285	58,687	60,872	62,693	64,082
SPP	54,511	64,194	67,335	72,202	75,938	78,965	81,941	84,529	89,670	91,884	96,946
ERCOT	45,619	49,148	48,746	49,190	52,059	57,325	65,130	78,179	84,671	92,273	99,600
MAPP	45,979	50,479	53,619	56,511	60,094	62,602	64,170	65,640	67,442	72,044	74,119
WSCC	71,616	76,451	83,354	86,074	89,446	95,237	99,382	102,122	106,654	110,734	115,228
TOTAL	588,402	635,665	647,590	674,512	693,905	713,385	742,419	774,356	799,859	831,288	862,235
GROSS OIL REQUIREMENTS IN PHYSICAL UNITS—(Thousands of Barrels)											
NPCC	111,068	117,856	101,443	95,851	87,372	69,091	57,194	51,677	55,933	60,962	70,328
MAAC	32,283	28,304	20,093	17,600	15,906	15,605	15,532	14,950	13,240	15,585	22,868
ECAR	4,255	4,400	4,611	4,990	5,367	5,705	6,055	6,435	6,802	7,093	7,157
SERC	59,363	53,634	42,810	39,296	37,664	38,138	38,829	43,392	45,825	49,110	54,722
MAIN	8,246	9,214	7,009	5,295	3,454	3,155	3,675	5,146	6,578	7,693	9,260
SPP	2,996	4,544	3,352	3,444	4,688	5,761	6,544	5,754	6,018	8,351	8,830
ERCOT	1,579	708	708	3,290	709	5,347	5,360	4,328	5,564	4,997	3,951
MAPP	706	771	837	958	1,340	2,195	996	1,164	1,569	1,382	1,154
WSCC	16,156	26,088	25,547	27,519	31,016	32,652	32,676	32,345	35,195	31,379	34,337
TOTAL	236,652	245,519	206,410	198,243	187,516	177,649	166,861	165,191	176,724	186,552	212,607
GROSS GAS REQUIREMENTS IN PHYSICAL UNITS—(Millions of Cubic Feet)											
NPCC	170,246	95,517	85,120	10,575	10,047	8,650	0	0	0	0	0
MAAC	72,268	72,090	53,591	43,414	41,514	38,929	39,337	32,412	33,834	33,568	10,118
ECAR	10,696	8,203	10,569	14,922	16,439	17,425	16,168	16,947	17,570	18,070	18,470
SERC	193,689	157,663	144,683	137,101	139,042	126,867	106,286	97,233	96,775	96,814	90,675
MAIN	12,942	13,732	7,170	4,188	3,350	3,194	3,193	4,159	5,120	5,082	7,091
SPP	1,041,455	974,556	951,388	832,071	813,059	818,195	818,524	823,559	807,811	819,150	836,553
ERCOT	981,835	1,037,018	1,091,919	1,086,026	1,065,160	1,034,608	1,046,028	1,013,951	1,003,586	1,006,032	1,004,672
MAPP	6,748	3,186	2,269	2,212	2,677	3,028	2,672	3,305	3,639	2,883	2,840
WSCC	593,486	811,541	656,827	630,500	591,454	560,402	554,240	553,023	523,626	542,392	493,969
TOTAL	3,083,365	3,173,506	3,003,536	2,761,009	2,682,742	2,611,298	2,586,448	2,544,589	2,491,961	2,523,991	2,464,388

Fig. 5 ACTUAL AND SCHEDULED ADDITIONS

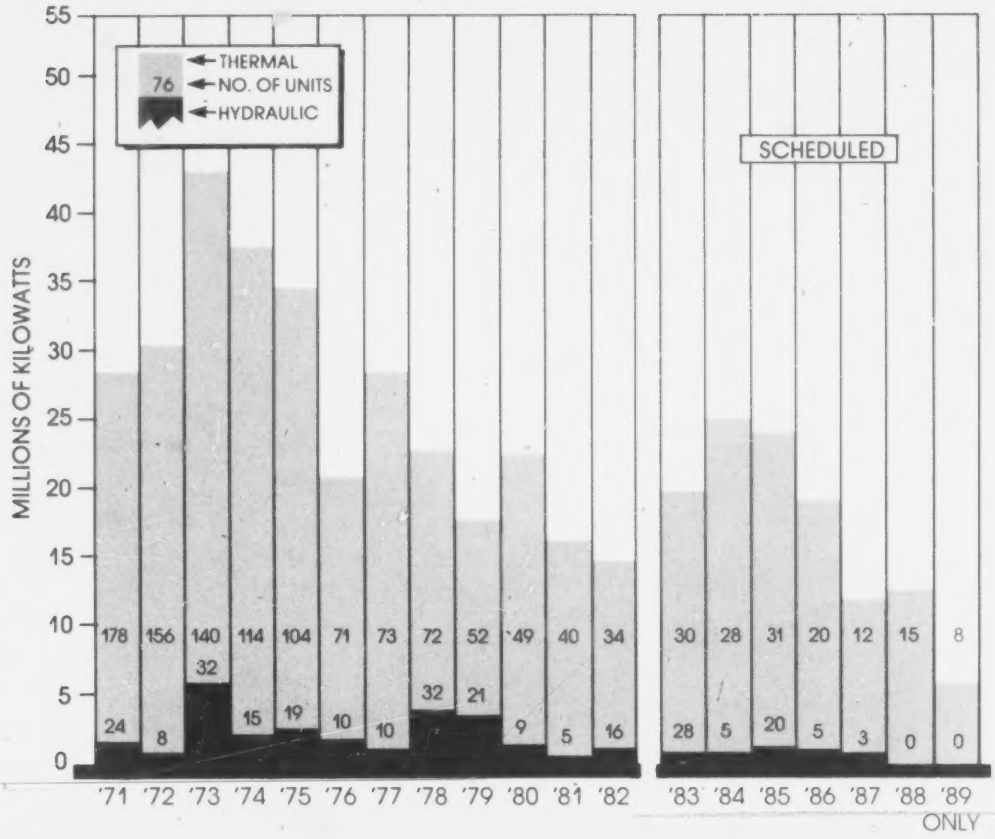


Table VIII NUMBER AND AGGREGATE CAPACITY OF THERMAL UNITS IN EXPANSION PROGRAM GROUPED ACCORDING TO SIZE RANGE AS OF APRIL 1, 1983 IN TERMS OF MANUFACTURERS' RATINGS OF THE UNITS

Size Range, Kw	No. Of Units	Aggregate Capacity, Kw	% of Total
1,300,000 Kw and Larger	13	17,273,407	13.7
1,200,000 to 1,299,999	10	12,217,617	9.7
1,100,000 to 1,199,999	25	28,994,161	23.0
1,000,000 to 1,099,999	4	4,354,232	3.5
900,000 to 999,999	5	4,836,428	3.8
800,000 to 899,999	14	11,615,918	9.2
700,000 to 799,999	11	8,000,597	6.4
600,000 to 699,999	26	16,876,101	13.4
500,000 to 599,999	21	11,048,838	8.8
400,000 to 499,999	13	5,505,174	4.4
300,000 to 399,999	7	2,573,557	2.1
200,000 to 299,999	5	1,270,174	1.0
100,000 to 199,999	4	584,000	0.5
Under 100,000	12	673,280	0.5
TOTAL THERMAL UNITS	170	125,823,484	100.0

NUCLEAR AND CONVENTIONAL STEAM TURBINE-GENERATORS, 300 MW AND LARGER, REMOVED FROM SCHEDULE AND DELAYED ONE YEAR OR MORE BETWEEN JAN. 1, 1983 AND APRIL 1, 1983

	Removed	Deferred One Year or More	Total Deferred and Removed
Nuclear			
Units	—	1	1
MW	—	1,253	1,253
Conventional			
Units	7	2	9
MW	4,563	885	5,448
TOTAL			
Units	7	3	10
MW	4,563	3,138	6,701

DELAYS AND REMOVALS FROM SCHEDULE

During 1982 the electric power systems removed from the expansion program seven nuclear units totaling 8,693 megawatts and seventeen conventional steam turbine-generators aggregating 11,524 megawatts. During the same twelve-month period the electric power systems also deferred by a year or more 33 steam turbine-generators, 300 megawatts or larger, totaling 24,062 megawatts, of which 11 units, totaling 11,303 megawatts, were nuclear.

During the first three months of 1983, seven conventional units rated at 4,563 megawatts were removed from schedule, but no nuclear units were removed from the expansion program. Deferred by a year or more, during the first quarter, were 3 steam turbine-generators, 300 megawatts or larger, totaling 3,138 megawatts, of which one unit, totaling 1,253 megawatts, was nuclear.

ADDITIONS TO ELECTRIC GENERATING CAPACITY

The number and aggregate capacity of new electric generating units placed in commercial operation during the first three months of 1983 are shown in the top portion of Table IX. The distribution of these units among the nine reliability councils of the United States is indicated in the second portion of the table, while the third portion of the table presents the same data classified according to ownership.

Table X presents the number and aggregate capacity of all new electric generating capacity on order, as of April 1, 1983 and scheduled for commercial operation during the last nine months of 1983 and later years. The second portion of the table presents this same information on the basis of the reliability councils in which the new capacity is to be installed, and the third portion of the table classifies the information according to ownership.

Tables IX and X include all steam turbine-generators, for both fossil and nuclear-fueled units, conventional hydraulic turbine-generators and those for pumped-storage plants, combustion turbine-generators, and diesel engine-generators, 4,000 kw and larger, of both domestic and foreign manufacture.

Table IX ADDITIONS TO ELECTRIC GENERATING CAPACITY DURING FIRST 3 MONTHS OF 1983 In Terms of Manufacturers' Ratings of the Units

	Thermal								Hydraulic					
	Steam Turbine-Generators				Combustion Turbine-Generators		Diesel Engine Generators							
	Conventional		Nuclear						Conventional		Pumped Storage		Total	
	No. of Units	Kw	No. of Units	Kw	No. of Units	Kw	No. of Units	Kw	No. of Units	Kw	No. of Units	Kw	No. of Units	Kw
ADDITIONS FIRST 3 MONTHS 1983	4	2,031,633	—	—	—	—	1	4,300	3	104,100	—	—	8	2,140,033
ADDITIONS BY REGION														
NPCC	—	—	—	—	—	—	—	—	—	—	—	—	—	—
MAAC	—	—	—	—	—	—	—	—	—	—	—	—	—	—
ECAR	1	392,00	—	—	—	—	—	—	1	25,000	—	—	2	417,000
SERC	1	707,633	—	—	—	—	—	—	—	—	—	—	1	707,633
MAIN	—	—	—	—	—	—	—	—	—	—	—	—	—	—
SPP	1	800,000	—	—	—	—	1	4,300	—	—	—	—	2	804,300
ERCOT	—	—	—	—	—	—	—	—	—	—	—	—	—	—
MAPP	—	—	—	—	—	—	—	—	—	—	—	—	—	—
WSCC	1	132,000	—	—	—	—	—	—	2	79,100	—	—	3	211,100
ADDITIONS BY OWNERSHIP														
Investor-Owned	4	2,031,633	—	—	—	—	—	—	1	25,000	—	—	5	2,056,633
Federal	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Municipal	—	—	—	—	—	—	1	4,300	1	40,000	—	—	2	44,300
Cooperative	—	—	—	—	—	—	—	—	—	—	—	—	—	—
State and Local	—	—	—	—	—	—	—	—	1	39,100	—	—	1	39,100

An indeterminate number of units amounting to several million kilowatts are also on order but have not been included in Table X because the units are either awaiting their first assignment of a scheduled date of commercial operation by the utility systems, or were once scheduled and have since been removed from the expansion program. It is probable that the majority of the orders in the second category (being held open as options by the manufacturers) will not be reactivated.

The accompanying Table VIII shows the number and aggregate capacity of thermal generating units in the expansion program (Table X) divided according to size range. It is significant to note from this tabulation that 82 units totaling 87.3 million kilowatts, or 69.3 percent of all the new thermal generating capacity on order and scheduled for service as of April 1, 1983, are in unit sizes of 700,000 kw and larger.

In sizes of 500,000 kw and larger, the aggregate capacity represents 91.5 percent of the total capacity shown.

Among the units under 100,000 kw, there are eight steam turbine-generators with an aggregate capacity of 372 mw, and 4 combustion turbine-generators, aggregating 301 mw.

The number and aggregate capacity of new thermal and hydraulic generating units 4,000 kw and larger, placed in commercial operation in the contiguous United States during the years 1971 through 1982, and those now scheduled for operation in 1983 and later years, including those placed in commercial operation during the first three months of 1983, are shown in Fig. 5.

Table X SCHEDULED ADDITIONS TO ELECTRIC GENERATING CAPACITY BASED ON SCHEDULED DATES OF COMMERCIAL OPERATION AS OF APRIL 1, 1983 In Terms of Manufacturers' Ratings of the Units

	Thermal								Hydraulic					
	Steam Turbine-Generators				Combustion Turbine-Generators		Diesel Engine Generators							
	Conventional		Nuclear						Conventional		Pumped Storage		Total	
	No. of Units	Kw	No. of Units	Kw	No. of Units	Kw	No. of Units	Kw	No. of Units	Kw	No. of Units	Kw	No. of Units	Kw
TOTAL SCHEDULED	104	55,253,117	62	70,269,487	4	300,880	—	—	45	1,873,058	13	4,028,800	228	131,725,342
SCHEDULED ADDITIONS BY YEARS—As of April 1, 1983														
1983	11	3,931,933	11	11,522,506	4	300,880	—	—	22	757,882	3	1,050,000	51	17,563,201
1984	19	9,261,148	14	15,346,971	—	—	—	—	5	355,900	—	—	38	24,964,019
1985	17	8,185,461	11	13,025,432	—	—	—	—	16	715,526	4	1,081,000	48	23,007,419
1986	10	6,119,172	10	11,574,758	—	—	—	—	2	43,750	3	1,050,000	25	18,787,680
1987	7	3,970,718	5	6,092,577	—	—	—	—	—	—	3	847,800	15	10,911,095
1988	10	5,725,608	5	5,985,842	—	—	—	—	—	—	—	—	15	11,711,450
1989 and Later	30	18,059,077	6	6,721,401	—	—	—	—	—	—	—	—	36	24,780,478
SCHEDULED ADDITIONS BY REGION														
NPCC	2	695,400	5	5,615,596	—	—	—	—	6	49,150	—	—	13	6,360,146
MAAC	5	3,054,008	5	5,471,770	—	—	—	—	5	168,750	—	—	15	8,694,528
ECAR	15	9,733,365	9	9,043,614	—	—	—	—	—	—	—	—	24	18,776,979
SERC	16	10,260,345	14	14,936,239	—	—	—	—	15	842,012	9	2,947,800	54	28,986,396
MAIN	3	994,012	8	9,217,773	—	—	—	—	—	—	—	—	11	10,211,785
SPP	14	8,557,095	5	5,957,233	2	108,000	—	—	1	27,000	1	31,000	23	14,680,328
ERCOT	13	8,250,499	4	4,945,412	—	—	—	—	2	66,000	—	—	19	13,261,911
MAPP	7	3,399,427	—	—	—	—	—	—	1	49,970	—	—	8	3,449,397
WSCC	29	10,308,966	12	15,081,850	2	192,880	—	—	15	670,176	3	1,050,000	61	27,303,872
SCHEDULED ADDITIONS BY OWNERSHIP														
Investor-Owned	73	41,757,571	54	61,141,993	2	192,880	—	—	18	735,412	12	3,997,800	159	107,825,656
Federal	—	—	5	5,289,755	—	—	—	—	18	957,000	1	31,000	24	6,277,755
Municipal	10	4,115,278	—	—	2	108,000	—	—	6	120,376	—	—	18	4,343,654
Cooperative	14	6,733,920	—	—	—	—	—	—	—	—	—	—	14	6,733,920
State and Local	7	2,646,348	3	3,837,739	—	—	—	—	3	60,270	—	—	13	6,544,357

NUCLEAR ELECTRIC POWER

During the first three months of 1983, no nuclear power generating units were ordered.

As of April 1, 1983, nuclear capacity accounts for 53 percent of the aggregate of the industry's scheduled expansion program.

As of the date of this survey, there were 75 nuclear units in commercial operation. These 75 units, which have a winter rating of 56.7 kilowatts, are listed in the accompanying tabulation. There were no additions to nuclear generating capacity during the first three months of 1983.

During the last nine months of 1983, eleven nuclear power units are scheduled for commercial operation. These eleven units have an aggregate capacity of 11.5 million kilowatts.

As of April 1983, there are 51 additional nuclear units on order and scheduled for commercial operation after 1983 in the contiguous United States, having an aggregate capacity of 58.7 million kilowatts. These units are included in the regional list given in Appendix I.

Investor-owned electric power systems are presently associated with 54 of the units listed in Appendix I as scheduled for future operation. Non-Federal government-owned systems are participating in three of the units, and the Federal government systems are constructing 5 nuclear units.

Table XI NUCLEAR POWER UNITS IN THE CONTIGUOUS U.S. AS OF APRIL 1, 1983

Name of System or Sponsor	Name or Location	Capability-MW Summer	Capability-MW Winter	Type of Reactor	Placed in Commercial Operation
Duquesne Light Company	Shippingport No. 1	60	60	LWBR	1957
Commonwealth Edison Company	Dresden No. 1	197	207	BWR	1960
Yankee Atomic Electric Company	Yankee No. 1	175	176	PWR	1961
Consumers Power Company	Big Rock Point	63	63	BWR	1962
Washington Public Power Supply System	Hanford	840	840	GMWC	1966
Connecticut Yankee Atomic Power Company	Haddam No. 1	555	580	PWR	1968
Southern California Edison Company and San Diego Gas & Electric Company	San Onofre No. 1	436	436	PWR	1968
Jersey Central Power & Light Company	Oyster Creek No. 1	620	650	BWR	1969
Niagara Mohawk Power Corporation	Nine Mile Point No. 1	610	610	BWR	1969
Rochester Gas and Electric Corporation	Ginna No. 1	470	470	PWR	1969
Northeast Utilities	Millstone Point No. 1	654	660	BWR	1970
Wisconsin Electric Power Company	Point Beach No. 1	495	495	PWR	1970
Carolina Power & Light Company	Robinson No. 2	665	700	PWR	1971
Dairyland Power Cooperative	La Crosse	46	46	BWR	1971
Northern States Power Company	Monticello No. 1	536	557	BWR	1971
Commonwealth Edison Company	Dresden No. 2	772	794	BWR	1971
Boston Edison Company	Pilgrim No. 1	670	670	BWR	1972
Commonwealth Edison Company	Quad Cities No. 1	768	789	BWR	1972
Commonwealth Edison Company	Quad Cities No. 2	769	789	BWR	1972
Florida Power & Light Company	Turkey Point No. 3	666	696	PWR	1972
Maine Yankee Atomic Power Company	Wiscasset	814	830	PWR	1972
Vermont Yankee Nuclear Power Corporation	Vernon	496	528	BWR	1972
Virginia Electric & Power Company	Surry No. 1	775	775	PWR	1972
Commonwealth Edison Company	Dresden No. 3	773	794	BWR	1973
Consumers Power Company	Palisades No. 1	635	740	PWR	1973
Duke Power Company	Oconee No. 1	860	860	PWR	1973
Duke Power Company	Oconee No. 2	860	860	PWR	1973
Florida Power and Light Company	Turkey Point No. 4	666	696	PWR	1973
Northern States Power Company	Prairie Island No. 1	503	523	PWR	1973
Omaha Public Power District	Fort Calhoun No. 1	439	457	PWR	1973
Tennessee Valley Authority	Browns Ferry No. 1	1,067	1,067	BWR	1973
Virginia Electric and Power Company	Surry No. 2	775	775	PWR	1973
Wisconsin Electric Power Company	Point Beach No. 2	495	495	PWR	1973
Arkansas Power and Light Company	Arkansas Nuclear No. 1	836	836	PWR	1974
Commonwealth Edison Company	Zion No. 1	1,040	1,040	PWR	1974

Table XI NUCLEAR POWER UNITS IN THE CONTIGUOUS U.S. AS OF APRIL 1, 1983

Name of System or Sponsor	Name of Location	Capability-MW Summer	Capability-MW Winter	Type of Reactor	Placed in Commercial Operation
Commonwealth Edison Company	Zion No. 2	1,040	1,040	PWR	1974
Consolidated Edison Company of NY, Inc	Indian Point No. 2	849	864	PWR	1974
Duke Power Company	Oconee No. 3	860	860	PWR	1974
Iowa Electric Light and Power Company	Arnold No. 1	480	510	BWR	1974
Metropolitan Edison Company	Three Mile Island No. 1	776	800	PWR	1974
Nebraska Public Power District	Cooper Nuclear No. 1	778	778	BWR	1974
Northern States Power Company	Prairie Island No. 2	500	520	PWR	1974
Philadelphia Electric Company	Peach Bottom No. 2	1,051	1,055	BWR	1974
Philadelphia Electric Company	Peach Bottom No. 3	1,035	1,035	BWR	1974
Wisconsin Public Service Corporation	Kewaunee No. 1	525	517	PWR	1974
Baltimore Gas & Electric Company	Calvert Cliffs No. 1	810	820	PWR	1975
Carolina Power & Light Company	Brunswick No. 2	790	790	BWR	1975
Georgia Power Company	Hatch No. 1	771	771	BWR	1975
Indiana & Michigan Electric Company	Cook No. 1	1,050	1,050	PWR	1975
Power Authority of the State of New York	Fitzpatrick No. 1	821	821	BWR	1975
Sacramento Utility District	Rancho Seco No. 1	875	903	PWR	1975
Tennessee Valley Authority	Browns Ferry No. 2	1,067	1,067	BWR	1975
Duquesne Light Company	Beaver Valley No. 1	800	800	PWR	1976
Florida Power and Light Company	St. Lucie No. 1	777	795	PWR	1976
Northeast Utilities	Millstone Point No. 2	864	864	PWR	1976
Portland General Electric Company	Trojan	1,080	1,080	PWR	1976
Power Authority of the State of New York	Indian Point No. 3	965	965	PWR	1976
Alabama Power Company	Farley No. 1	807	807	PWR	1977
Baltimore Gas and Electric Company	Calvert Cliffs No. 2	825	860	PWR	1977
Carolina Power and Light Company	Brunswick No. 1	790	790	BWR	1977
Florida Power Corporation	Crystal River No. 3	782	807	PWR	1977
Public Service Electric and Gas Company	Salem Nuclear No. 1	1,079	1,100	PWR	1977
Tennessee Valley Authority	Browns Ferry No. 3	1,067	1,067	BWR	1977
Toledo Edison Company	Davis-Besse No. 1	906	906	PWR	1977
Indiana & Michigan Electric Company	Cook No. 2	1,100	1,100	PWR	1978
Virginia Electric & Power Company	North Anna No. 1	898	907	PWR	1978
Georgia Power Company	Hatch No. 2	771	771	BWR	1979
Public Service Company of Colorado	Fort St. Vrain No. 1	200	200	HTGR	1979
Arkansas Power & Light Company	Arkansas Nuclear No. 2	858	858	PWR	1980
Virginia Electric & Power Company	North Anna No. 2	870	870	PWR	1980
Alabama Power Company	Farley No. 2	812	812	PWR	1981
Duke Power Company	McGuire No. 1	1,180	1,180	PWR	1981
Public Service Electric & Gas Co.	Salem Nuclear No. 2	1,106	1,120	PWR	1981
Tennessee Valley Authority	Sequoyah No. 1	1,128	1,128	PWR	1981
Tennessee Valley Authority	Sequoyah No. 2	1,148	1,148	PWR	1982
TOTAL		55,992	56,696		

BWR = Boiling Water Reactor
GMWC = Graphite Moderated, Water Cooled Reactor
HTGR = High Temperature, Gas Cooled Reactor
LWBR = Light Water Breeder Reactor
PWR = Pressurized Water Reactor

PART II/MANUFACTURE OF HEAVY ELECTRIC POWER EQUIPMENT IN THE U.S.A.

This section of the report presents a summary, as of April 1, 1983, of information relative to shipments, new orders, and scheduled production of heavy electric power equipment by the leading manufacturers in the United States.

Orders placed by U.S. electric power systems with foreign manufacturers for conventional and nuclear steam turbine-generators, generators for hydraulic turbines, hydraulic turbines, and combustion turbine-generators are shown as an additional line below the domestic manufacturers' total on the respective equipment tables.

The accompanying order and backlog synopsis table (Table XII) also incorporates orders to foreign manufacturers for certain types of equipment.

Table XIX, on the manufacture of power transformers, shows data for four size classifications above 501 Kva rather than the two size classifications used previous to 1978.

Information relative to estimated open manufacturing capacity, where given, is based on current estimates by the individual manufacturers of the aggregate capacity of new equipment, over and above that on order and scheduled for delivery as of April 1, 1983, that could be produced and shipped during the years indicated—provided orders were placed in the very near future.

Table XII CAPACITY OF NEW HEAVY POWER EQUIPMENT PLACED ON ORDER WITH MANUFACTURERS DURING 1982 AND FIRST THREE MONTHS OF 1983, AND TOTAL CAPACITY ON ORDER AND SCHEDULED FOR SHIPMENT AS OF APRIL 1, 1983 TO U.S. ELECTRIC POWER SYSTEMS

	Ordered		Total On Order and Scheduled for Shipment as of 4-1-83
	1982	First 3 Months 1983	
Electric Generating Units (4,000 Kw and Larger)			
Steam Turbine-Generators, Kw			
Conventional	93,500 (a)	—	56,900,556 (a)
Nuclear	—	—	8,175,481
Combustion Turbine-Generators, Kw	35,790	—	503,940
Generators for Hydraulic Turbines, Kw	279,326 (a)	108,001 (a)	2,831,876 (a)
TOTAL	408,616 (a)	108,001 (a)	68,411,853 (a)
Steam Generators, 1,000 Lbs Steam Per Hour	1,000	—	217,016
Nuclear Power Reactors (50,000 Kwe and Larger)	—	—	87,247,000
Hydraulic Turbines, Hp	—	—	4,979,480
Power Transformers, Mva(b)	78,003	19,567	105,954

(a) Includes equipment on order with foreign manufacturers
(b) Includes U.S. Industrials

Table XIII MANUFACTURE OF ELECTRIC GENERATING EQUIPMENT—STEAM AND HYDRAULIC UNITS*—4,000 Kw and Larger**

	Shipped		Scheduled as of April 1, 1983							Total Scheduled for Shipment as of 4-1-83	New Orders Booked 1-1-83 to 4-1-83
	1982	First 3 Months 1983	Last 9 Months 1983	1983	1984	1985	1986	1987	1988 and Later		
U.S. Electric Power Systems											
Units	26	4	14	18	15	10	7	18	45	109	—
Kw	7,307,625	2,176,400	3,913,251	6,089,651	6,452,620	6,449,602	3,757,249	9,970,761	31,378,644	61,922,127	—
U.S. Industrials											
Units	15	1	8	9	6	2	—	—	—	16	1
Kw	258,190	12,500	282,800	295,300	252,600	78,800	—	—	—	614,200	53,730
Outside U.S.											
Units	10	2	15	17	8	—	—	1	4	28	—
Kw	2,361,675	670,000	6,047,249	6,717,249	3,835,574	—	—	706,496	2,980,496	13,569,815	—
Total											
Units	51	7	37	44	29	12	7	19	49	153	1
Kw	9,927,490	2,858,900	10,243,300	13,102,200	10,540,794	6,528,402	3,757,249	10,677,257	34,359,140	76,106,142	53,730

*Does not include combustion turbine-generators, but does include steam turbine-generators for nuclear power plants.
**Manufacturers' ratings.

Table XIV MANUFACTURE OF STEAM TURBINE-GENERATORS—4,000 Kw and Larger*

	Shipped		Scheduled as of April 1, 1983							Total Scheduled for Shipment as of 4-1-83	New Orders Booked 1-1-83 to 4-1-83
	1982	First 3 Months 1983	Last 9 Months 1983	1983	1984	1985	1986	1987	1988 and Later		
U.S. Electric Power Systems											
Units	13	3	10	13	10	10	7	18	45	100	—
Kw	6,456,275	2,101,400	3,713,251	5,814,651	6,253,670	6,449,602	3,757,249	9,970,761	31,378,644	61,523,177	—
U.S. Industrials											
Units	15	1	8	9	6	2	—	—	—	16	1
Kw	258,190	12,500	282,800	295,300	252,600	78,800	—	—	—	614,200	53,730
Outside U.S.											
Units	10	2	15	17	8	—	—	1	4	28	—
Kw	2,361,675	670,000	6,047,249	6,717,249	3,835,574	—	—	706,496	2,980,496	13,569,815	—
Total											
Units	38	6	33	39	24	12	7	19	49	144	1
Kw	9,927,490	2,858,900	10,243,300	13,102,200	10,540,794	6,528,402	3,757,249	10,677,257	34,359,140	75,707,192	53,730

*Manufacturers' ratings.

Table XIV-A MANUFACTURE OF CONVENTIONAL STEAM TURBINE-GENERATORS—4,000 Kw and Larger* (Included in Table XIV)

	Shipped		Scheduled as of April 1, 1983							Total Scheduled for Shipment as of 4-1-83	New Orders Booked 1-1-83 to 4-1-83
	1982	First 3 Months 1983	Last 9 Months 1983	1983	1984	1985	1986	1987	1988 and Later		
U.S. Electric Power Systems											
Units	11	3	10	13	10	9	7	17	39	92	—
Kw	3,942,240	2,101,400	3,713,251	5,814,651	6,253,670	5,289,602	3,757,249	9,554,258	24,779,666	53,347,696	—
U.S. Industrials											
Units	15	1	8	9	6	2	—	—	—	16	1
Kw	258,190	12,500	282,800	295,300	252,600	78,800	—	—	—	614,200	53,730
Outside U.S.											
Units	9	2	12	14	8	—	—	—	2	22	—
Kw	1,554,000	670,000	3,245,574	3,915,574	3,835,574	—	—	—	1,294,000	8,375,148	—
Total											
Units	35	6	30	36	24	11	7	17	41	130	1
Kw	5,754,430	2,783,900	7,241,625	10,025,525	10,341,844	5,368,402	3,757,249	9,554,258	26,073,666	62,337,044	53,730
Orders to Foreign Manufacturers											
Units	3	4	1	5	3	3	—	2	1	10	—
Kw	466,100	1,330,860	25,000	1,355,860	643,000	884,000	—	1,207,000	160,000	2,919,000	—

*Manufacturers' ratings.

Table XIV-B MANUFACTURE OF NUCLEAR STEAM TURBINE-GENERATORS—50,000 Kw and Larger* (Included in Table XIV)

	Shipped		Scheduled as of April 1, 1983							Total Scheduled for Shipment as of 4-1-83	New Orders Booked 1-1-83 to 4-1-83
	1982	First 3 Months 1983	Last 9 Months 1983	1983	1984	1985	1986	1987	1988 and Later		
U.S. Electric Power Systems											
Units	2	—	—	—	—	1	—	1	6	8	—
Kw	2,514,035	—	—	—	—	1,160,000	—	416,507	6,598,978	8,175,481	—
U.S. Industrials											
Units	—	—	—	—	—	—	—	—	—	—	—
Kw	—	—	—	—	—	—	—	—	—	—	—
Outside U.S.											
Units	1	—	3	3	—	—	—	1	2	6	—
Kw	807,675	—	2,801,675	2,801,675	—	—	—	706,496	1,686,496	5,194,667	—
Total											
Units	3	—	3	3	—	1	—	2	8	14	—
Kw	3,321,710	—	2,801,675	2,801,675	—	1,160,000	—	1,122,999	8,285,474	13,370,148	—
Orders to Foreign Manufacturers											
Units	—	—	—	—	—	—	—	—	—	—	—
Kw	—	—	—	—	—	—	—	—	—	—	—

*Manufacturers' ratings.

Table XV MANUFACTURE OF GENERATORS FOR HYDRAULIC TURBINES*—4,000 Kw and Larger**

	Shipped		Scheduled as of April 1, 1983							Total Scheduled for Shipment as of 4-1-83	New Orders Booked 1-1-83 to 4-1-83
	1982	First 3 Months 1983	Last 9 Months 1983	1983	1984	1985	1986	1987	1988 and Later		
U.S. Electric Power Systems											
Units	13	1	4	5	5	—	—	—	—	9	—
Kw	851,350	75,000	200,000	275,000	198,850	—	—	—	—	398,950	—
U.S. Industrials											
Units	—	—	—	—	—	—	—	—	—	—	—
Kw	—	—	—	—	—	—	—	—	—	—	—
Outside U.S.											
Units	—	—	—	—	—	—	—	—	—	—	—
Kw	—	—	—	—	—	—	—	—	—	—	—
Total											
Units	13	1	4	5	5	—	—	—	—	9	—
Kw	851,350	75,000	200,000	275,000	198,950	—	—	—	—	398,950	—
Orders to Foreign Manufacturers											
Units	4	1	5	6	3	4	4	1	—	17	1
Kw	146,000	5,900	214,576	220,476	101,250	632,700	1,127,700	281,700	—	2,357,926	108,000

*Includes generators for pumped-storage plants.
**Manufacturers' ratings.

Table XVI MANUFACTURE OF CONVENTIONAL STEAM GENERATORS—450 Psi Pressure and Higher

	Shipped		Scheduled as of April 1, 1983							Total Scheduled for Shipment as of 4-1-83	New Orders Booked 1-1-83 to 4-1-83
	1982	First 3 Months 1983	Last 9 Months 1983	1983	1984	1985	1986	1987	1988 and Later		
U.S. Electric Power Systems											
Units	17	5	5	10	9	12	7	3	6	42	1
M lb/hr	62,397	19,844	26,044	45,888	42,521	55,444	35,966	20,025	27,066	207,066	4,700
U.S. Industrials											
Units	15	1	3	4	—	—	—	—	—	3	—
M lb/hr	4,973	650	999	1,649	—	—	—	—	—	999	—
Outside U.S.											
Units	10	2	3	5	1	2	1	—	—	7	—
M lb/hr	15,219	6,731	10,390	17,121	4,579	8,327	3,748	—	—	27,044	—
Total											
Units	42	8	11	19	10	14	8	3	6	52	1
M lb/hr	82,589	27,225	37,433	64,658	47,100	63,771	39,714	20,025	27,066	235,109	4,700

Table XVII MANUFACTURE OF HYDRAULIC TURBINES*—5,000 Horsepower and Larger

	Shipped		Scheduled as of April 1, 1983							Total Scheduled for Shipment as of 4-1-83	New Orders Booked 1-1-83 to 4-1-83
	1982	First 3 Months 1983	Last 9 Months 1983	1983	1984	1985	1986	1987	1988 and Later		
U.S. Electric Power Systems											
Units	—	—	8	8	7	3	—	—	4	22	—
Hp	—	—	1,700,420	1,700,420	1,743,060	156,000	—	—	1,380,000	4,979,480	—
U.S. Industrials											
Units	—	—	—	—	—	—	—	—	—	—	—
Hp	—	—	—	—	—	—	—	—	—	—	—
Outside U.S.											
Units	1	1	3	4	—	3	1	—	—	7	—
Hp	24,140	320,000	960,000	1,280,000	—	275,400	91,800	—	—	1,327,200	—
Total											
Units	1	1	11	12	7	6	1	—	4	29	—
Hp	24,140	320,000	2,660,420	2,980,420	1,730,060	431,400	91,800	—	1,380,000	6,306,680	—
Orders to Foreign Manufacturers											
Units	—	—	—	—	—	—	—	—	—	—	—
Hp	—	—	—	—	—	—	—	—	—	—	—

*Includes hydraulic turbines for pumped-storage plants.

Table XVIII MANUFACTURE OF COMBUSTION TURBINE-GENERATORS—4,000 Kw and Larger*

	Shipped		Scheduled as of April 1, 1983							Total Scheduled for Shipment as of 4-1-83	New Orders Booked 1-1-83 to 4-1-83
	1982	First 3 Months 1983	Last 9 Months 1983	1983	1984	1985	1986	1987	1988 and Later		
U.S. Electric Power Systems											
Units	1	1	1	2	—	—	—	1	1	3	—
Kw	35,790	96,440	96,440	192,880	—	—	—	224,500	75,000	395,940	—
U.S. Industrials											
Units	7	2	—	2	—	—	—	—	—	—	—
Kw	613,140	133,140	—	133,140	—	—	—	—	—	—	—
Outside U.S.											
Units	13	—	2	2	1	—	—	—	—	3	2
Kw	941,220	—	159,900	159,900	35,900	—	—	—	—	195,800	71,800
Total											
Units	21	3	3	6	1	—	—	1	1	6	2
Kw	1,590,150	229,580	256,340	485,920	35,900	—	—	224,500	75,000	591,740	71,800
Orders to Foreign Manufacturers											
Units	—	—	—	—	—	—	—	—	—	—	—
Kw	—	—	—	—	—	—	—	—	—	—	—

*Manufacturers' ratings.

Table XIX MANUFACTURE OF POWER TRANSFORMERS—501 Kva and Larger

		Shipped		Scheduled as of April 1, 1983								
		1982	First 3 Months 1983	Last 9 Months 1983	1983	1984	1985	1986	1987	1988 and Later	Total Scheduled for Shipment as of 4-1-83	New Orders Booked 1-1-82 to 4-1-83
501 to 10,000 Kva												
U.S. Electric Power Systems and U.S. Industrials	Units	4,753	1,123	1,859	2,982	45	11	15	7	27	1,964	1,121
	Mva	13,161	2,822	4,910	7,732	185	19	151	70	298	5,633	2,710
Outside U.S.	Units	490	114	151	265	—	—	—	—	—	151	43
	Mva	1,231	300	440	740	—	—	—	—	—	440	103
TOTAL	Units	5,243	1,237	2,010	3,247	45	11	15	7	27	2,115	1,164
	Mva	14,392	3,122	5,350	8,472	185	19	151	70	298	6,073	2,813
10,001 to 30,000 Kva												
U.S. Electric Power Systems and U.S. Industrials	Units	796	136	284	420	35	15	12	—	10	356	124
	Mva	21,154	3,358	6,487	9,845	932	614	332	—	330	8,695	2,982
Outside U.S.	Units	35	—	12	12	—	—	—	—	4	16	12
	Mva	795	—	478	478	—	—	—	—	241	719	420
TOTAL	Units	831	136	296	432	35	15	12	—	14	372	136
	Mva	21,949	3,358	6,965	10,323	932	614	332	—	571	9,414	3,402
30,001 to 100,000 Kva												
U.S. Electric Power Systems and U.S. Industrials	Units	235	45	108	153	44	20	2	4	12	190	39
	Mva	15,048	2,529	6,630	9,159	2,492	1,101	120	200	891	11,434	2,235
Outside U.S.	Units	21	2	2	4	1	—	—	—	—	3	—
	Mva	1,001	137	160	297	53	—	—	—	—	213	—
TOTAL	Units	256	47	110	157	45	20	2	4	12	193	39
	Mva	16,049	2,666	6,790	9,456	2,545	1,101	120	200	891	11,647	2,235
100,001 Kva and Larger												
U.S. Electric Power Systems and U.S. Industrials	Units	197	39	103	142	53	25	9	7	23	220	30
	Mva	64,381	13,896	32,797	46,693	19,985	10,507	3,922	4,306	8,675	80,192	11,640
Outside U.S.	Units	7	—	8	8	1	2	—	—	—	11	—
	Mva	3,083	—	3,464	3,464	217	434	—	—	—	4,115	—
TOTAL	Units	204	39	111	150	54	27	9	7	23	231	30
	Mva	67,464	13,896	36,261	50,157	20,202	10,941	3,922	4,306	8,675	84,307	11,640
TOTAL (501 Kva and Larger)												
U.S. Electric Power Systems and U.S. Industrials	Units	5,981	1,343	2,354	3,697	177	71	38	18	72	2,730	1,314
	Mva	113,744	22,605	50,824	73,429	23,594	12,241	4,525	4,576	10,194	105,954	19,567
Outside U.S.	Units	553	116	173	289	2	2	—	—	4	181	55
	Mva	6,110	437	4,542	4,979	270	434	—	—	241	5,487	523
TOTAL	Units	6,534	1,459	2,527	3,986	179	73	38	18	76	2,911	1,369
	Mva	119,854	23,042	55,366	78,408	23,864	12,675	4,525	4,576	10,435	111,441	20,090
Estimated Open Manufacturing Capacity for Production of Additional Power Transformers, 501 Kva and Larger, Mva					47,000	102,000	113,000	129,000	129,000	132,000 (1988 only)		

Table XX MANUFACTURE OF NUCLEAR REACTORS—50,000 Kwe and Larger*

	Completed		Scheduled as of April 1, 1983							Total Scheduled for Completion as of 4-1-83	New Orders Booked 1-1-83 to 4-1-83
	1982	First 3 Months 1983	Last 9 Months 1983	1983	1984	1985	1986	1987	1988 and Later		
U.S. Electric Power Systems											
Units	1	—	13	13	14	10	11	7	23	78	—
Kwe	1,148,000	—	14,095,000	14,095,000	14,419,000	11,245,000	12,388,000	8,193,000	26,907,000	87,247,000	—
Outside U.S.											
Units	1	—	6	6	8	4	4	3	6	31	—
Kwe	951,000	—	4,838,000	4,838,000	6,585,000	3,715,000	3,456,000	2,857,000	5,844,000	27,295,000	—
Total											
Units	2	—	19	19	22	14	15	10	29	109	—
Kwe	2,099,000	—	18,933,000	18,933,000	21,004,000	14,960,000	15,844,000	11,050,000	32,751,000	114,542,000	—

*Manufacturers' ratings.

APPENDIX I

Scheduled Additions to Electric Generating Capacity Based on Scheduled Dates of Commercial Operations as of April 1, 1983, and Capacity Placed in Service During the First Three Months of 1983.

Includes all electric generating units 4,000 kw and larger on order and scheduled for service by the U.S. Electric Power Systems.

SYMBOLS:

Investor-Owned	I
Federal	F
Municipal	M
Cooperative	C
State & Local	SL
Thermal	
Conventional steam turbine-generator	T
Nuclear steam turbine-generator	N
Combustion turbine-generator	G
Diesel engine-generator	D
Hydraulic	
Hydraulic turbine-generator	H
Pumped-Storage	
Pumped-storage turbine-generator	S
Reversible pumped-storage turbine-generator	R
Combined-Cycle	
Combustion turbine-generator for combined-cycle operation	GC
Conventional steam turbine-generator for combined-cycle operation	TC

* Denotes units placed in commercial operation during the first three months of 1983.

° Denotes units added to the expansion program since October 1, 1982.

+ Denotes multiple ownership of the unit. In such cases, the name of the participating power system in whose service area the installation will be located is shown. In case the location does not fall within the service area of any of the participants, the name of the power system shown is the first in alphabetical order among the major participants.

NOTES: Kilowatts shown for individual generating units represent, in most cases, the net operating capability expected by the power systems; in other cases they represent the manufacturer's nameplate rating of the unit.

It is the convention in listing combined-cycle projects that the first line item is the combustion turbine-generator and the second line item is the steam turbine-generator. Combined-cycle operation is indicated by the symbols GC and TC in a brace:

GC
TC }

NPCC

	System	Station	Owner-ship	Type	Exp. Net Capability	Sched. Date of Operation
○	BURLINGTON VERMONT	MC NEIL NO 1	M	T	50,000	1984
○	CENTRAL MAINE POWER CO	HIRAM	I	H	9,100	1985
	LONG ISLAND LIGHTING CO	SHOREHAM NO 1	I	N	809,000	1984
	NEW YORK STATE ELECTRIC & GAS CO	SOMERSET NO 1	I	T	625,000	1984
	NEW YORK STATE ELECTRIC & GAS CO	UPPER MECHANICSVILLE #1	I	H	8,400	1983
	NEW YORK STATE ELECTRIC & GAS CO	UPPER MECHANICSVILLE #2	I	H	8,400	1983
	NIAGARA MOHAWK POWER CORP	GRANBY NO 1	I	H	5,000	1983
	NIAGARA MOHAWK POWER CORP	GRANBY NO 2	I	H	5,000	1983
+	NIAGARA MOHAWK POWER CORP	NINE MILE POINT NO 2	I	N	1,080,000	1986
	NORTHEAST UTILITIES	HADLEY FALLS NO 2	I	H	15,000	1983
+	NORTHEAST UTILITIES	MILLSTONE POINT NO 3	I	N	1,150,000	1986
+	PUBLIC SERVICE CO OF NEW HAMPSHIRE	SEABROOK NO 1	I	N	1,150,000	1985
+	PUBLIC SERVICE CO OF NEW HAMPSHIRE	SEABROOK NO 2	I	N	1,150,000	1987

MAAC

	BALTIMORE GAS & ELECTRIC CO	BRANDON SHORES NO 1	I	T	637,000	1984
	BALTIMORE GAS & ELECTRIC CO	BRANDON SHORES NO 2	I	T	640,000	1988
	DELMARVA POWER & LIGHT CO	VIENNA NO 9	I	T	375,000	1985
	GENERAL PUBLIC UTILITIES	COAL NO 1	I	T	625,000	1983
	GENERAL PUBLIC UTILITIES	COAL NO 2	I	T	625,000	1984
+	PENNSYLVANIA POWER & LIGHT CO	SUSQUEHANNA NO 1	I	N	1,050,000	1983
+	PENNSYLVANIA POWER & LIGHT CO	SUSQUEHANNA NO 2	I	N	1,050,000	1984
	PHILADELPHIA ELECTRIC CO	LIMERICK NO 1	I	N	1,055,000	1985
	PHILADELPHIA ELECTRIC CO	LIMERICK NO 2	I	N	1,055,000	1988
+	PUBLIC SERVICE ELECTRIC & GAS CO	HOPE CREEK NO 1	I	N	1,067,000	1986
	SAFE HARBOR WATER POWER CORP	SAFE HARBOR NO 8	I	H	38,000	1986
	SAFE HARBOR WATER POWER CORP	SAFE HARBOR NO 9	I	H	37,000	1985
	SAFE HARBOR WATER POWER CORP	SAFE HARBOR NO 10	I	H	37,000	1985
	SAFE HARBOR WATER POWER CORP	SAFE HARBOR NO 11	I	H	38,000	1985
	SAFE HARBOR WATER POWER CORP	SAFE HARBOR NO 12	I	H	38,000	1985

ECAR

	AMERICAN ELECTRIC POWER CO	RACINE DAM A	I	H	20,000	1983 *
	AMERICAN ELECTRIC POWER CO	ROCKPORT NO 1	I	T	1,300,000	1984
	AMERICAN ELECTRIC POWER CO	ROCKPORT NO 2	I	T	1,300,000	1986
	BIG RIVERS ELECTRIC CORP	D B WILSON NO 1	C	T	395,000	1984
	CINCINNATI GAS & ELECTRIC CO	EAST BEND NO 1	I	T	600,000	1988
+	CINCINNATI GAS & ELECTRIC CO	ZIMMER NO 1	I	N	800,000	1983
+	CLEVELAND ELECTRIC ILLUMINATING CO	PERRY NO 1	I	N	1,205,000	1985
+	CLEVELAND ELECTRIC ILLUMINATING CO	PERRY NO 2	I	N	1,205,000	1988
	CONSUMERS POWER CO	MIDLAND NO 1	I	N	530,000	1984
	CONSUMERS POWER CO	MIDLAND NO 2	I	N	805,000	1983
+	DETROIT EDISON CO	BELLE RIVER NO 1	I	T	676,000	1984
	DETROIT EDISON CO	BELLE RIVER NO 2	I	T	676,000	1985
+	DETROIT EDISON CO	FERMI NO 2	I	N	1,093,000	1983
+	DUQUESNE LIGHT CO	BEAVER VALLEY NO 2	I	N	833,000	1986
	EAST KENTUCKY POWER COOP	SMITH NO 1	C	T	600,000	1992
	INDIANAPOLIS POWER & LIGHT CO	PETERSBURG NO 4	I	T	515,000	1986
	KENTUCKY UTILITIES CO	GHENT NO 4	I	T	500,000	1984
	KENTUCKY UTILITIES CO	HANCOCK NO 1	I	T	650,000	1993
	KENTUCKY UTILITIES CO	HANCOCK NO 2	I	T	650,000	1994
	LOUISVILLE GAS & ELECTRIC CO	TRIMBLE COUNTY NO 1	I	T	495,000	1987

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ECAR
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System	Station	Owner-ship	Type	Exp. Net Capability	Sched. Date of Operation
LOUISVILLE GAS & ELECTRIC CO	TRIMBLE COUNTY NO 2	I	T	495,000	1993
NORTHERN INDIANA PUBLIC SERVICE CO	SCHAHFER NO 17	I	T	344,000	1983 *
NORTHERN INDIANA PUBLIC SERVICE CO	SCHAHFER NO 18	I	T	344,000	1986
+ PUBLIC SERVICE CO OF INDIANA	MARBLE HILL NO 1	I	N	1,130,000	1986
+ PUBLIC SERVICE CO OF INDIANA	MARBLE HILL NO 2	I	N	1,130,000	1988
SOUTHERN INDIANA GAS & ELECTRIC CO	BROWN NO 2	I	T	250,000	1985

ALABAMA POWER CO	HARRIS NO 1	I	H	58,600	1983
ALABAMA POWER CO	HARRIS NO 2	I	H	58,600	1983
ALABAMA POWER CO	MILLER NO 2	I	T	666,000	1985
ALABAMA POWER CO	MILLER NO 3	I	T	666,000	1989
ALABAMA POWER CO	MILLER NO 4	I	T	666,000	1991
ALABAMA POWER CO	MITCHELL NO 5	I	H	64,000	1985
ALABAMA POWER CO	MITCHELL NO 6	I	H	64,000	1985
ALABAMA POWER CO	MITCHELL NO 7	I	H	64,000	1985
CAROLINA POWER & LIGHT CO	HARRIS NO 1	I	N	900,000	1986
CAROLINA POWER & LIGHT CO	HARRIS NO 2	I	N	900,000	1990
CAROLINA POWER & LIGHT CO	MAYO NO 1	I	T	720,000	1983 *
CAROLINA POWER & LIGHT CO	MAYO NO 2	I	T	720,000	1992
DUKE POWER CO	CATAWBA NO 1	I	N	1,145,000	1985
DUKE POWER CO	CATAWBA NO 2	I	N	1,145,000	1987
DUKE POWER CO	MCGUIRE NO 2	I	N	1,180,000	1984
FLORIDA POWER CORP	CRYSTAL RIVER NO 5	I	T	670,000	1984
+ FLORIDA POWER & LIGHT CO	ST LUCIE NO 2	I	N	802,000	1983
○ GEORGIA POWER CO	BARTLETTS FERRY 5 & 6	I	H	96,000	1985
GEORGIA POWER CO	ROCKY MOUNTAIN NO 1	I	R	282,667	1987
GEORGIA POWER CO	ROCKY MOUNTAIN NO 2	I	R	282,667	1987
GEORGIA POWER CO	ROCKY MOUNTAIN NO 3	I	R	282,666	1987
+ GEORGIA POWER CO	SCHERER NO 2	I	T	808,000	1984
+ GEORGIA POWER CO	SCHERER NO 3	I	T	809,000	1987
+ GEORGIA POWER CO	SCHERER NO 4	I	T	808,000	1989
+ GEORGIA POWER CO	VOGTLE NO 1	I	N	1,150,000	1987
+ GEORGIA POWER CO	VOGTLE NO 2	I	N	1,150,000	1988
+ JACKSONVILLE FLORIDA	ST JOHNS RIVER PARK NO 1	M	T	525,000	1985
+ JACKSONVILLE FLORIDA	ST JOHNS RIVER PARK NO 2	M	T	525,000	1987
+ ORLANDO FLORIDA	STANTON NO 1	M	T	415,000	1986
+ PROJECT MANAGEMENT CORP	CLINCH RIVER BREEDER	F	N	350,000	1990
SEMINOLE ELECTRIC COOP	SEMINOLE NO 1	C	T	600,000	1983
SEMINOLE ELECTRIC COOP	SEMINOLE NO 2	C	T	600,000	1985
+ SOUTH CAROLINA ELECTRIC & GAS CO	SUMMER NO 1	I	N	900,000	1983
SOUTH CAROLINA PUBLIC SERVICE AUTHORITY	CROSS NO 2	SL	T	450,000	1984
SOUTH CAROLINA PUBLIC SERVICE AUTHORITY	CROSS NO 1	SL	T	450,000	1991
TAMPA ELECTRIC CO	BIG BEND NO 4	I	T	417,000	1985
TENNESSEE VALLEY AUTHORITY	BELLEFONTE NO 1	F	N	1,176,975	1986
TENNESSEE VALLEY AUTHORITY	BELLEFONTE NO 2	F	N	1,176,975	1987
TENNESSEE VALLEY AUTHORITY	WATTS BAR NO 1	F	N	1,177,000	1984
TENNESSEE VALLEY AUTHORITY	WATTS BAR NO 2	F	N	1,177,000	1985
U S ARMY CORPS OF ENGINEERS	HARTWELL NO 5 (HALF)	F	H	40,000	1983
U S ARMY CORPS OF ENGINEERS	HARTWELL NO 5 (HALF)	F	H	40,000	1983
U S ARMY CORPS OF ENGINEERS	R B RUSSELL NO 1	F	H	75,000	1984
U S ARMY CORPS OF ENGINEERS	R B RUSSELL NO 2	F	H	75,000	1984
U S ARMY CORPS OF ENGINEERS	R B RUSSELL NO 3	F	H	75,000	1985

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System	Station	Owner-ship	Type	Exp. Net Capability	Sched. Date of Operation
U S ARMY CORPS OF ENGINEERS	R B RUSSELL NO 4	F	H	75,000	1985
U S ARMY CORPS OF ENGINEERS	ST STEPHEN NO 1	F	H	20,000	1983
U S ARMY CORPS OF ENGINEERS	ST STEPHEN NO 2	F	H	20,000	1983
U S ARMY CORPS OF ENGINEERS	ST STEPHEN NO 3	F	H	20,000	1983
+ VIRGINIA ELECTRIC & POWER CO	BATH COUNTY NO 1	I	R	350,000	1985
+ VIRGINIA ELECTRIC & POWER CO	BATH COUNTY NO 2	I	R	350,000	1985
+ VIRGINIA ELECTRIC & POWER CO	BATH COUNTY NO 3	I	R	350,000	1986
+ VIRGINIA ELECTRIC & POWER CO	BATH COUNTY NO 4	I	R	350,000	1985
+ VIRGINIA ELECTRIC & POWER CO	BATH COUNTY NO 5	I	R	350,000	1986
+ VIRGINIA ELECTRIC & POWER CO	BATH COUNTY NO 6	I	R	350,000	1986

MAIN

COMMONWEALTH EDISON CO	BRAIDWOOD NO 1	I	N	1,120,000	1985
COMMONWEALTH EDISON CO	BRAIDWOOD NO 2	I	N	1,120,000	1986
COMMONWEALTH EDISON CO	BYRON NO 1	I	N	1,120,000	1984
COMMONWEALTH EDISON CO	BYRON NO 2	I	N	1,120,000	1985
COMMONWEALTH EDISON CO	LASALLE COUNTY NO 1	I	N	1,078,000	1983
COMMONWEALTH EDISON CO	LASALLE COUNTY NO 2	I	N	1,078,000	1983
+ ILLINOIS POWER CO	CLINTON NO 1	I	N	950,000	1984
MARQUETTE MICHIGAN	SHIRAS NO 3	M	T	44,000	1983
UNION ELECTRIC CO	CALLAWAY NO 1	I	N	1,120,000	1985
WISCONSIN ELECTRIC POWER CO	PLEASANT PRAIRIE NO 2	I	T	580,000	1985
+ WISCONSIN POWER & LIGHT CO	EDGEWATER NO 5	I	T	380,000	1985

SPP

ARKANSAS POWER & LIGHT CO	INDEPENDENCE NO 1	I	T	816,000	1983 *
+ ARKANSAS POWER & LIGHT CO	INDEPENDENCE NO 2	I	T	816,000	1985
+ CAJUN ELECTRIC POWER COOP	BIG CAJUN TWO NO 3	C	T	540,000	1983
CAJUN ELECTRIC POWER COOP	OXBOW NO 1	C	T	512,000	1988
CAJUN ELECTRIC POWER COOP	OXBOW NO 2	C	T	512,000	1994
GRAND RIVER DAM AUTHORITY	CHOUTEAU NO 2	SL	T	490,000	1985
GULF STATES UTILITIES CO	NELSON NO 5	I	T	540,000	1994
+ GULF STATES UTILITIES CO	RIVER BEND NO 1	I	N	940,000	1985
o HUGOTON KANSAS	MUNICIPAL PWR PLANT	M	D	4,300	1983 *
+ KANSAS GAS & ELECTRIC CO	WOLF CREEK NO 1	I	N	1,150,000	1984
+ KANSAS POWER & LIGHT CO	JEFFREY ELEC CENTER NO 3	I	T	680,000	1983
LOUISIANA POWER & LIGHT CO	WATERFORD NO 3	I	N	1,104,000	1984
LOUISIANA POWER & LIGHT CO	WILTON NO 1	I	T	800,000	1990
LOUISIANA POWER & LIGHT CO	WILTON NO 2	I	T	800,000	1992
+ MISSISSIPPI POWER & LIGHT CO	GRAND GULF NO 1	I	N	1,250,000	1983
+ MISSISSIPPI POWER & LIGHT CO	GRAND GULF NO 2	I	N	1,250,000	1988
OKLAHOMA GAS & ELECTRIC CO	MUSKOGEE NO 6	I	T	515,000	1984
+ SOUTHWESTERN ELECTRIC POWER CO	DOLET HILLS NO 1	I	T	640,000	1986
+ SOUTHWESTERN ELECTRIC POWER CO	PIRKEY NO 1	I	T	640,000	1985
SOUTHWESTERN PUBLIC SERVICE CO	TOLK NO 2	I	T	508,000	1985
o SPRINGFIELD MISSOURI	SOUTHWEST NO 1	M	G	44,000	1983
o SPRINGFIELD MISSOURI	SOUTHWEST NO 2	M	G	44,000	1983
SUNFLOWER ELECTRIC COOP	HOLCOMB NO 1	C	T	280,000	1983
U S ARMY CORPS OF ENGINEERS	CANNON NO 2	F	H	28,000	1985
U S ARMY CORPS OF ENGINEERS	CANNON NO 1	F	H	32,000	1985

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System	Station	Ownership	Type	Exp. Net Capability	Sched. Date of Operation
o+BRAZOS ELECTRIC POWER COOP	SAN MIGUEL NO 2	C	T	400,000	1990
+CENTRAL POWER & LIGHT CO	COLETO CREEK NO 2	I	T	700,000	1988
HOUSTON LIGHTING & POWER CO	LIMESTONE NO 1	I	T	700,000	1986
HOUSTON LIGHTING & POWER CO	LIMESTONE NO 2	I	T	700,000	1987
HOUSTON LIGHTING & POWER CO	MALAKOFF NO 1	I	T	600,000	1989
HOUSTON LIGHTING & POWER CO	MALAKOFF NO 2	I	T	600,000	1989
+HOUSTON LIGHTING & POWER CO	SOUTH TEXAS NO 1	I	N	1,250,000	1987
+HOUSTON LIGHTING & POWER CO	SOUTH TEXAS NO 2	I	N	1,250,000	1989
oINTERNATIONAL WATER & BOUNDARY COMM	AMISTAD NO 1	F	H	33,000	1983
oINTERNATIONAL WATER & BOUNDARY COMM	AMISTAD NO 2	F	H	33,000	1983
+LOWER COLORADO RIVER AUTHORITY	FAYETTE NO 3	SL	T	400,000	1988
TEXAS MUNICIPAL POWER AGENCY	GIBBONS CREEK NO 1	M	T	400,000	1983
+TEXAS UTILITIES CO SYSTEM	COMANCHE PEAK NO 1	I	N	1,150,000	1984
+TEXAS UTILITIES CO SYSTEM	COMANCHE PEAK NO 2	I	N	1,150,000	1985
+TEXAS UTILITIES CO SYSTEM	FOREST GROVE NO 1	I	T	750,000	1989
+TEXAS UTILITIES CO SYSTEM	MARTIN LAKE NO 4	I	T	750,000	1991
+TEXAS UTILITIES CO SYSTEM	TWIN OAK NO 1	I	T	750,000	1988
+TEXAS UTILITIES CO SYSTEM	TWIN OAK NO 2	I	T	750,000	1990
+WEST TEXAS UTILITIES CO	OKLAUNION NO 1	I	T	640,000	1986

MAPP

System	Station	Ownership	Type	Exp. Net Capability	Sched. Date of Operation
BASIN ELECTRIC POWER COOP	ANTELOPE VALLEY NO 1	C	T	416,000	1984
+BASIN ELECTRIC POWER COOP	ANTELOPE VALLEY NO 2	C	T	416,000	1986
+IOWA ELECTRIC LIGHT & POWER CO	GUTHRIE COUNTY NO 1	I	T	650,000	1988
+IOWA-ILLINOIS GAS & ELECTRIC CO	LOUISA NO 1	I	T	650,000	1983
MUSCATINE IOWA	MUSCATINE NO 9	M	T	150,000	1983
NEBRASKA PUBLIC POWER DISTRICT	KINGSLEY NO 2	SL	H	38,000	1985
+NORTHERN STATES POWER CO	SHERBURNE COUNTY NO 3	I	T	800,000	1988
OTTER TAIL POWER CO	SPWD NO 1 (INDEF)	I	T	108,000	1988

WSCC

System	Station	Ownership	Type	Exp. Net Capability	Sched. Date of Operation
ARIZONA PUBLIC SERVICE CO	CHOLLA NO 5	I	T	340,000	1993
+ARIZONA PUBLIC SERVICE CO	PALO VERDE NO 1	I	N	1,270,000	1984
+ARIZONA PUBLIC SERVICE CO	PALO VERDE NO 2	I	N	1,270,000	1985
+ARIZONA PUBLIC SERVICE CO	PALO VERDE NO 3	I	N	1,270,000	1986
CALIFORNIA DEPT OF WATER RESOURCES	BOTTLE ROCK	SL	T	55,000	1984
CALIFORNIA DEPT OF WATER RESOURCES	W E WARNE NO 2	SL	H	38,000	1983 *
COLORADO-UTE ELECTRIC ASSOCIATION	CRAIG NO 3	C	T	400,000	1984
DESERET G & T COOP	BONANZA NO 1	C	T	360,000	1984
+LOS ANGELES CALIFORNIA	INTERMOUNTAIN NO 1	M	T	761,000	1986
+LOS ANGELES CALIFORNIA	INTERMOUNTAIN NO 2	M	T	761,000	1987
METROPOLITAN WATER DISTRICT	PERRIS NO 1	M	H	7,900	1983
oMETROPOLITAN WATER DISTRICT	RED MOUNTAIN NO 1	M	H	5,900	1984
oMETROPOLITAN WATER DISTRICT	VALLEY VIEW NO 1	M	H	4,100	1985
+MONTANA POWER CO	COLSTRIP NO 3	I	T	700,000	1984
+MONTANA POWER CO	COLSTRIP NO 4	I	T	700,000	1985
PACIFIC GAS & ELECTRIC CO	DIABLO CANYON NO 1	I	N	1,084,000	1984
PACIFIC GAS & ELECTRIC CO	DIABLO CANYON NO 2	I	N	1,106,000	1984
PACIFIC GAS & ELECTRIC CO	GEYSERS NO 16	I	T	110,000	1985
PACIFIC GAS & ELECTRIC CO	GEYSERS NO 18	I	T	114,000	1983 *
PACIFIC GAS & ELECTRIC CO	GEYSERS NO 20	I	T	110,000	1986

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WSCC
Continued

System	Station	Ownership		Exp. Net Capability	Sched. Date of Operation	
PACIFIC GAS & ELECTRIC CO	HELMS NO 1	I	R	374,000	1983	
PACIFIC GAS & ELECTRIC CO	HELMS NO 2	I	R	374,000	1983	
PACIFIC GAS & ELECTRIC CO	HELMS NO 3	I	R	375,000	1983	
PACIFIC GAS & ELECTRIC CO	KERCKHOFF NO 2	I	H	151,000	1983	
+PACIFIC POWER & LIGHT CO	WYODAK NO 2	I	T	310,000	1989	
PLAINS ELECTRIC GENERATION&TRANSMISSION	ESCALANTE NO 1	C	T	210,000	1984	
PLATTE RIVER POWER AUTHORITY	RAWHIDE NO 1	SL	T	250,000	1984	
PUBLIC SERVICE CO OF COLORADO	PAWNEE NO 2	I	T	485,000	1989	
+PUBLIC SERVICE CO OF NEW MEXICO	NEW MEXICO STA NO 1	I	T	500,000	1995	
PUBLIC SERVICE CO OF NEW MEXICO	NEW MEXICO STA NO 2	I	T	500,000	1996	
PUBLIC SERVICE CO OF NEW MEXICO	NEW MEXICO STA NO 3	I	T	500,000	1997	
PUBLIC SERVICE CO OF NEW MEXICO	NEW MEXICO STA NO 4	I	T	500,000	1998	
+PUGET SOUND POWER & LIGHT CO	SKAGIT NO 1	I	N	1,288,000	1991	
+PUGET SOUND POWER & LIGHT CO	SKAGIT NO 2	I	N	1,288,000	1993	
PUGET SOUND POWER & LIGHT CO	FREDONIA NO 1	I	G	123,500	1983	
PUGET SOUND POWER & LIGHT CO	FREDONIA NO 2	I	G	123,500	1983	
SACRAMENTO UTILITY DISTRICT	GEOTHERMAL NO 1	M	T	65,000	1983	
SACRAMENTO UTILITY DISTRICT	JONES FORK	M	H	10,000	1986	
SALT RIVER POWER DISTRICT	CORONADO NO 3	SL	T	350,000	1991	
oSAN DIEGO GAS & ELECTRIC CO	HEBER NO 2	I	T	45,000	1987	
+SIERRA PACIFIC POWER CO	VALMY NO 2	I	T	250,000	1985	
SOLANO IRRIGATION DISTRICT	MONTICELLO NO 1	SL	H	3,500	1983	
SOLANO IRRIGATION DISTRICT	MONTICELLO NO 2	SL	H	3,500	1983	
+SOUTHERN CALIFORNIA EDISON CO	SAN ONOFRE NO 2	I	N	1,100,000	1983	
+SOUTHERN CALIFORNIA EDISON CO	SAN ONOFRE NO 3	I	N	1,100,000	1983	
+SOUTHERN CALIFORNIA EDISON CO	SOLAR ONE	I	T	10,000	1985	
TACOMA WASHINGTON	MAYFIELD NO 4	M	H	39,000	1983	*
+TACOMA WASHINGTON	SUMMER FALLS NO 1	M	H	47,000	1985	
+TACOMA WASHINGTON	SUMMER FALLS NO 2	M	H	47,000	1985	
TUCSON GAS & ELECTRIC CO	SPRINGERVILLE NO 1	I	T	350,000	1985	
TUCSON GAS & ELECTRIC CO	SPRINGERVILLE NO 2	I	T	350,000	1987	
U S ARMY CORPS OF ENGINEERS	LIBBY NO 5	F	H	121,000	1984	
U S BUREAU OF RECLAMATION	GRAND COULEE PG-9	F	H	50,000	1983	
U S BUREAU OF RECLAMATION	GRAND COULEE PG-10	F	H	50,000	1983	
U S BUREAU OF RECLAMATION	GRAND COULEE PG-11	F	H	50,000	1983	
U S BUREAU OF RECLAMATION	GRAND COULEE PG-12	F	H	50,000	1983	
U S BUREAU OF RECLAMATION	MT ELBERT NO 2	F	H	100,000	1984	
UTAH POWER & LIGHT CO	HUNTER NO 3	I	T	400,000	1983	
UTAH POWER & LIGHT CO	HUNTER NO 4	I	T	400,000	1988	
UTAH POWER & LIGHT CO	MILFORD GEOTHERMAL	I	T	20,000	1984	
+WASHINGTON PUBLIC POWER SUPPLY SYSTEM	WNP NO 2	SL	N	1,100,000	1984	
+WASHINGTON PUBLIC POWER SUPPLY SYSTEM	WNP NO 3	SL	N	1,240,000	1986	
+WASHINGTON PUBLIC POWER SUPPLY SYSTEM	WNP NO 1	SL	N	1,250,000	1991	
WASHINGTON WATER POWER CO	KETTLE FALLS	I	T	42,200	1983	

NUMBER OF UNITS = 236 AMOUNT OF EXP. NET CAPABILITY = 128,950,450

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1111 19th Street, N.W.
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